Potential Energy-Saving Impacts of Extending Daylight Saving Time:

A National Assessment

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EXECUTIVE SUMMARY

The Energy Policy Act (EPAct) of 2005 (P.L 109-58) amends the Uniform Time Act of 1966 (P.L. 89-387) to increase the portion of the year that would be subject to Daylight Saving Time (DST). The legislation calls for extending the duration of DST in the spring from the first Sunday of April to the second week of March, and in the fall from the last week of October to the first week of November. The legislation also calls for an evaluation of the impact of Extended Daylight Saving Time (EDST) on energy consumption in the United States and submission of a report to Congress nine months after the effective date of the extension.

This study provides an analysis of the *potential* national energy-savings impacts of EDST, using available 2004 data; however, it is not intended to fulfill the reporting requirement of EPAct section 110(c). In addition to providing an estimate of potential energy savings, this study identifies data and methods that could support future analyses, including the study required by section 110(c).

Using information obtained from review of the literature and available 2004 energy data, this study analyzed the potential energy impacts due to changes in electricity consumption. Potential non-energy impacts that may result from the extended DST were not analyzed in detail in this study. These other potential impacts include children traveling to school during darkness, traffic accident rates, crime rates, electronics changeover to new EDST dates, airline schedule changes, and agricultural work scheduling.

Key Findings on Energy Savings

Although the values are approximate, the main results of the analysis were:

- Total potential *electricity* savings benefits of EDST are relatively small. Total potential electrical savings of 1 Tera Watt-hour (TWh) are estimated (with an uncertainty range of ± 40 percent), corresponding to 0.4 percent per day for each day of EDST or 0.03 percent of electricity use over the year. The United States consumed 3,548 TWhs in 2004.

- Total potential *energy* benefits are small. Total potential primary energy savings are estimated from 7 to 26 Trillion Btu (TBtu), or 0.01 percent to 0.03 percent of total annual U.S. energy consumption.

- Potential savings would occur over a several-hour period in the evening, with small increases in energy use in the morning hours.

- Potential savings in southern regions of the United States are estimated to be lower than those in northern regions.

- On a daily percentage basis, potential savings are slightly greater during the March extension of DST than the November extension.

Other Considerations

In addition to the potential electricity and energy savings estimated in this study, there are other potential energy-related impacts from extended DST such as changes in transportation vehicle miles traveled, and non-electricity building heating and cooling. The previous studies of these non-electric energy sectors, most notably the 1975 Department of Transportation (DOT) study, found that DST had less impact on transportation and non-electric building energy changes than the energy changes in the electric sector. Regarding gasoline consumption associated with DST, both the 1975 DOT study and a recent examination of state-level Travel Monitoring and Survey data by the Florida Department of Transportation concluded that vehicle travel, a proxy for gasoline consumption, was not impacted by changes to DST. The potential non-electric energy impacts were not further examined in this study due to the limited availability of supporting data for analysis of these factors.

Study Approach

The study is based on a statistical analysis of recent hourly electricity use in 2004 from 12 electric utilities representing different regions across the country. Electricity use in the morning and evening hours expected to be the most affected by DST were compared for the weeks before and after the current DST dates. This comparison involved the development of regression models that were used to account for daylight, weather, and other factors. These models were then used to predict the percentage changes in the electricity demand by hour that would potentially occur in the extended DST periods in March and November. The resulting percentage changes in electricity use were then applied to each region of the country to determine an approximate magnitude of the potential national electricity savings. Marginal costs for regionally representative electric utilities were used to identify the likely fuels that were being consumed to generate electricity at those hours of the day where EDST is expected to have an impact. In this manner, the potential total energy savings were estimated.

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ACRONYMS

AEO	Annual Energy Outlook
AZN	Arizona/ New Mexico/ Southern Nevada Power Area
CEC	California Energy Commission
CNV	California/Mexico Power Area
DOE	Department of Energy
DDST	Double Daylight Saving Time
DOT	Department of Transportation
DST	Daylight Saving Time
ECAR	East Central Area Reliability Coordination Agreement
EDST	Extended Daylight Saving Time
EERE	Office of Energy Efficiency and Renewable Energy
ELCAP	Load and Consumer Assessment Program
ERCOT	Electric Reliability Council of Texas
ES&D	Electricity Supply & Demand Database
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
HELM	Hourly Electric Load Model
ISO-NE	Independent System Operator – New England
LADWP	Los Angeles Department of Water and Power
LCD	Local Climatological Data
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MRO	Midwest Reliability Organization

NBS	National Bureau of Standards
NCDC	National Climatic Data Center
NEL	Net Energy for Load
NEMass	Northeast Massachusetts
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NWP	Northwest Power Pool Area
O&M	Operations and Maintenance
RECS	Residential Energy Consumption Surveys
RMP	Rocky Mountain Power Area
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
ST	Standard Time
WECC	Western Electricity Coordinating Council

PART 1

HIGHLIGHTS OF KEY FINDINGS ON ENERGY-SAVINGS POTENTIAL

1 Key Findings

This section summarizes the key findings on estimated total potential electricity savings and variation by period of day, by season, and by North-South regions; what is known about transportation fuel use and Daylight Saving Time (DST); and estimated potential primary energy savings. The analysis approach is briefly described along with the organization of the remainder of the report.[1]

1.1 Introduction

Section 110 of the Energy Policy Act (EPAct) of 2005 (P.L. 109-58) amends the Uniform Time Act of 1966 (P.L. 89-387) to increase the portion of the year that would be subject to DST. The legislation calls for extension in the spring from the first Sunday of April to the second week of March (three or four weeks earlier than current law), and in the fall from the last week of October to the first week of November (one week later than current law).[2] The legislation also calls for an evaluation of the impact of Extended Daylight Saving Time (EDST) on energy consumption in the United States and submission of a report to Congress nine months after the effective date of the extension.

This study provides an analysis of the *potential* national energy-savings impacts of EDST, using available 2004 data, however, it is not intended to replace or fulfill the study called for in EPAct section 110(c). In addition to providing an estimate of potential energy savings, this study identifies data and methods that could support future analyses, including the study required by section 110(c).

Table 1.1 lists some of the possible energy effects of EDST. Some are potentially quantifiable, while others require a significant amount of behavioral analysis to understand their potential impact.

Few comprehensive analyses have been conducted to estimate potential energy impacts of DST or EDST for the United States. The most comprehensive study was conducted by the Department of Transportation (DOT) in 1975. The California Energy Commission (CEC) conducted a detailed econometric analysis for proposing state-level changes in Double Daylight Saving Time (DDST) in 2001. Both the DOT study and CEC study recognized that the largest energy-saving potential was in the form of electricity, and that other fuels may be impacted but to a smaller degree.

This study focuses on quantitative analysis of electricity consumption impacts while recognizing, but not analyzing, other potential energy impacts, such as gasoline consumption associated with

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[1] This report was completed for DOE by David B. Belzer (PNNL), Stanton W. Hadley (ORNL), Frank Southworth (ORNL), and J. Michael MacDonald (ORNL). Douglas J. Arent (NREL) directed the work. Jeff Dowd (DOE/EERE) was the DOE project officer.

[2] Depending on the calendar for a particular year, the spring savings would be for either three weeks or for four weeks, as the DST is slated to start on the second Sunday in March. Over a period of years, the three-week acceleration of DST would occur about 57 percent of the time. In the fall, the savings would always be for one week.

changes in vehicle miles traveled during EDST and non-electric heating and cooling-fuel consumption in buildings.

Table 1.1. Potential Energy Effects of EDST

Energy Use	Possible Effect
Home Lighting	• Some lighting use will be reduced in early evening, and total evening amounts will be reduced if bedtimes are not delayed • Some lighting use will increase in rooms normally sunlit in the morning
Commercial Lighting	• Outdoor lighting use will decrease if lights are turned off at the same time in the evening as during Standard Time • Reduced need for lighting indoors for businesses that employ daylighting
Heating and Cooling	• Heating needs may increase in morning hours as more people are active before sunshine-induced heating • Residential cooling needs may increase with more people home during daylight hours • Commercial and industrial space heating and cooling needs may fluctuate depending on outside temperature and internal heating demand
Appliance Use	• Delayed or reduced use of indoor appliances as people engage in more outdoor activities or other activities outside the home
Total Electricity	• Increases and decreases from the different end uses will have either a net negative or positive change in electricity needs • Amounts will depend on the region and time
Total Fuel for Electricity	• Shift and reduction in electricity use may change the type and quantity of total fuel used for generation
Electricity Capacity	• Shifts in electricity requirements may lower the daily peak demand and consequent electric capacity requirements • Because the extensions are in March and November, which are typically periods of low demand, insufficient capacity is generally not a problem
Transportation	• Increased evening daylight may increase the amount of driving for discretionary activities • Increased evening daylight may spread the amount of travel at peak times, reducing congestion and decreasing energy use • Increased evening trips while already traveling may consolidate activities and reduce weekend travel, reducing overall trip miles • Net change in traffic patterns could be positive or negative

The focus is on quantitative analysis of electricity impacts because previous studies indicated electricity consumption is the area where most impact is expected to occur. This study has found limited new available data on vehicle miles traveled and non-electric heating and cooling-fuel consumption in buildings during DST to enable a full assessment of these potential non-electricity impacts from EDST.

Although non-energy impacts resulting from the extended DST may be important considerations, they were not examined in this study because they were not requested in the Energy Policy Act legislation that focused on energy consumption. Potential non-energy impacts include children traveling to school during darkness, traffic accident rates, changes in amounts and patterns of crime, electronics changeover to new EDST dates, airline schedule changes, and agricultural work scheduling. Many of these considerations were widely vetted in the 1975, 1985, and 2001 discussions of these issues and in various Congressional testimonies. Little new information from more recent studies on these issues is available in 2006.

1.2 Electricity Savings

The analysis performed in this study looked at potential electricity and energy savings from EDST, breaking the savings down by time of day, season, and region. The main results are presented below.

The analysis indicates the total potential electricity and energy benefits are small. Total potential electrical savings of 1 Tera Watt-hour (TWh) are estimated, corresponding to 0.4 percent per day for each day of EDST or 0.03 percent of electricity use over the year. The United States consumed 3,548 TWhs in 2004. The details on how this result was determined are provided in Section 3.

Total potential electricity savings across all regions are shown in Table 1.2.

Table 1.2. Regional Net Electricity Savings from EDST

	SPRING (3/1/04 – 4/30/04)			FALL (10/1/04 – 11/30/04)			
NERC Region[3]	Regional Energy (TWh)	Utility Savings over 2 months (%)	Regional Savings (TWh)	Regional Energy (TWh)	Utility Savings over 2 months (%)	Regional Savings (TWh)	Annual Savings (TWh)
ECAR	87	0.18%	0.160	85	0.05%	0.043	0.202
ERCOT	41	0.05%	0.022	45	0.01%	0.006	0.027
FRCC	32	0.13%	0.040	35	0.02%	0.007	0.047
MAAC	44	0.14%	0.061	42	0.06%	0.025	0.086
MAIN	42	0.20%	0.086	43	0.05%	0.023	0.109
MRO	23	0.19%	0.045	25	0.05%	0.012	0.057
NPCC	45	0.18%	0.081	46	0.05%	0.025	0.106
SERC	124	0.08%	0.102	132	0.03%	0.037	0.140
SPP	28	0.05%	0.015	29	0.01%	0.004	0.018
WECC-AZN	18	0.07%	0.012	18	0.02%	0.004	0.016
WECC-CNV	43	0.21%	0.093	45	0.05%	0.024	0.116
WECC-NWP	35	0.11%	0.038	37	0.04%	0.015	0.053
WECC-RMP	9	0.14%	0.013	9	0.04%	0.004	0.017
Total	571		0.768	589		0.228	0.996

The error bound for the amount of electricity change is roughly ± 40 percent, according to the analysis described in Appendix A. This translates into potential electricity savings of 0.6 to 1.4 TWh annually for the entire country.

Electricity savings variation by period of day, by season, and by North-South regions

Table 1.3 presents estimates of the predicted average daily change in electricity use during the spring season based on combining the predicted percentage changes in the morning and evening hours. Table 1.4 shows similar results for the fall season.

[3] The U.S. portion of the North American Electric Reliability Council (NERC) electricity reliability regions.

Potential electricity savings would occur over a several-hour period in the evening (1800 to 2100 hours), with small increases in electricity consumption in the morning hours (e.g., 0500 to 0800 hours).[4] Due to later sunrises under EDST, most parts of the nation would consume slightly more electricity on a daily basis in the morning hours than is the case under the current DST calendar. Looking over both the spring and fall results in Tables 1.3 and 1.4, the range of *increased* consumption during the morning hours is between 0.01 percent to 0.17 percent per day over the spring and fall seasons. During the evening hours, the *decrease* in consumption ranges between 0.19 percent to 0.76 percent over the two seasons.

The total estimated electricity savings (shown in the Net Chg. column of Tables 1.3 and 1.4) are slightly greater during the spring than during the fall. For five locations (Detroit, Dayton, Chicago, Miami, and Los Angeles), the net percentage savings in the spring are 0.1 percent to 0.2 percent higher than those in the fall, while most other locations show the same savings when rounded to the nearest tenth of a percent.[5] The spring energy savings are a more important influence on total annual savings as EDST will affect three or four weeks in the spring and only one week in the fall.

Table 1.3. Estimated Percentage Change in Daily Electricity Use: Spring DST under EPAct 2005

Location	Morning (%)	Evening (%)	Net Change (%)
Boston (NE Mass)	0.08%	- 0.58%	- 0.5%
New York	0.04%	- 0.44%	- 0.4%
Detroit	0.09%	- 0.64%	- 0.6%
Dayton	0.06%	- 0.55%	- 0.5%
Chicago	0.08%	- 0.67%	- 0.6%
Texas Municipal	0.10%	- 0.26%	- 0.2%
Atlanta	0.08%	- 0.32%	- 0.2%
Miami	0.07%	- 0.45%	- 0.4%
Denver	0.13%	- 0.55%	- 0.4%
Portland, OR	0.17%	- 0.45%	- 0.3%
Los Angeles	0.14%	- 0.76%	- 0.6%

Potential electricity savings in southern regions of the United States are estimated to be lower than those in northern regions. Comparison of the percentage changes in Tables 1.3 and 1.4 indicate average daily savings of total electrical energy in the spring of between 0.4 percent and 0.6 percent in the North, and between about 0.2 percent and 0.4 percent in the South. These North-South electricity savings would apply to each day affected by the EDST provision. Los Angeles is an exception to the three other locations in the South (Texas, Atlanta, and Miami), as its climate is considerably cooler than the other locations. In the fall, the savings in the southern locations range between 0.1 percent and 0.2 percent (again, excluding Los Angeles), compared to the estimated potential savings in the northern sites that are generally 0.4 percent or 0.5 percent per day.

[4] Predicted savings for individual hours of the day for each location are shown in specific tables in Section 3 of the report.

[5] The sole exception is New York, where the predicted savings are slightly higher in the fall than the spring. Fall estimates for Chicago were not generated, as hourly electricity consumption was not available when the statistical analysis was undertaken.

Table 1.4. Estimated Percentage Change in Daily Electricity Use: Fall DST under EPAct 2005

Location	Morning (%)	Evening (%)	Net Change (%)
Boston (NE Mass)	0.05%	- 0.59%	- 0.5%
New York	0.01%	- 0.51%	- 0.5%
Detroit	0.08%	- 0.51%	- 0.4%
Dayton	0.09%	- 0.53%	- 0.4%
Texas Municipal	0.08%	- 0.19%	- 0.1%
Atlanta	0.04%	- 0.27%	- 0.2%
Miami	0.09%	- 0.26%	- 0.2%
Denver	0.09%	- 0.50%	- 0.4%
Portland, OR	0.05%	- 0.39%	- 0.3%
Los Angeles	0.11%	- 0.59%	- 0.5%

The analysis in this study also shows that the estimated electricity savings during the evening hours are generally slightly lower in the fall season as compared to the spring. The analysis did not reveal any statistically meaningful differences between spring and fall in the increased use of morning electricity from DST.

1.3 Effect on Transportation Fuel Use

One potential impact of extended DST is on gasoline consumption associated with changes in transportation vehicle miles traveled during extended daylight hours. The analysis of this issue by the DOT in 1975 found that daylight saving time appears to have had no discernible effect on gasoline consumption associated with vehicle travel demand. DOT concluded that if there were subtle influences that DST exerts on travel demand, they are so small, so diffuse, and so intermixed with the effects of other factors that it was not possible to detect. During the course of this study, only a single new study on travel demand and DST was found. The recent examination of state level Travel Monitoring and Survey data by the Florida Department of Transportation indicated that in Florida the total travel was not impacted by changes to DST.[6] However, no national level conclusions can be drawn from this single new finding.

1.4 Energy Savings (primary energy)

Total potential energy savings are estimated to be between 7 and 26 Trillion Btu (TBtu), or 0.01 percent-0.03 percent of total annual U.S. energy consumption. This range of potential total energy savings was calculated based on the potential electricity savings as noted above, and accounted for the variation in electricity generation fuel (e.g., coal, natural gas, and petroleum fuels) by region. Regional differences in utility variable costs are accounted for in the range of potential energy savings calculated.[7] The details on how this result was determined are provided in Section 4.

[6] Florida Department of Transportation's and the Federal Highway Administration's analysis of Florida data on travel patterns associated with changes in daylight saving time.

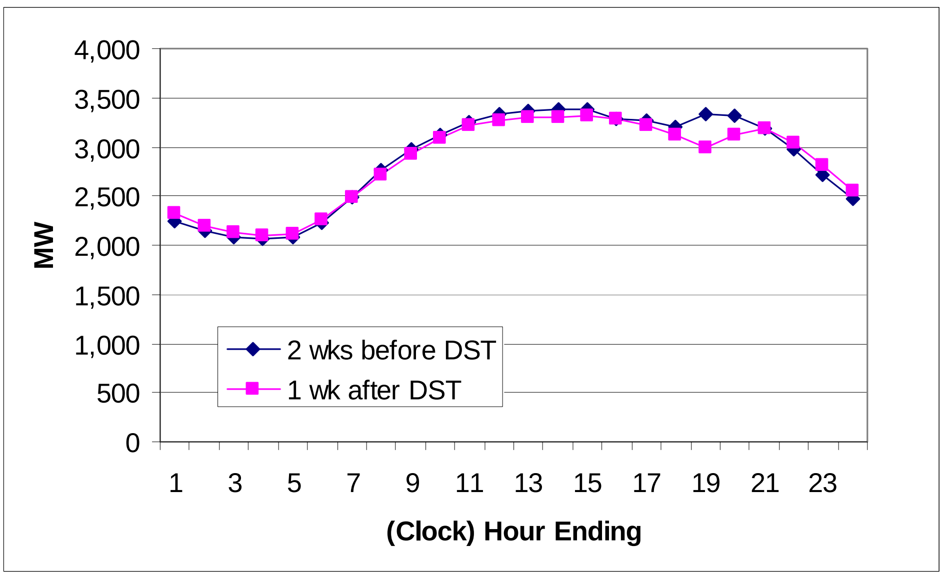
[7] Utility variable costs impact the "dispatch" of different generation sources. Variation in generation sources impacts the fuel used for generation and efficiency of converting the primary fuel to electricity. Analysis based on EIA data for ranges of cost data allowed for the determination of a range of possible fuel and total energy savings.

1.5 Analysis Approach

The results of this study were based on an analysis of the potential electricity and corresponding total energy savings due to possible changes in DST. Following a review of the literature, estimates of potential energy impacts were derived from statistical analysis of hourly electricity use from 12 utilities representing different regions across the country. Electricity use in the morning and evening hours (0500 to 0800 hours and 1800 to 2100 hours, respectively) that were expected to be the most affected by DST were compared for the weeks before and after the current DST dates.

An example of the average hourly electricity demand before and after the Spring 2004 DST transition for Los Angeles is shown in Figure 1.1, where electricity demand is plotted as a function of time, and the two lines shown compare the two weeks prior to DST to the week following the DST transition. The figure clearly shows that the most significant reduction in the electricity demand after DST occurs primarily during the hours ending at 7 p.m. (hour 19) and 8 p.m. (hour 20). Even with less daylight in the morning, electricity demand increases only slightly. Los Angeles is only one example; the pattern of observed changes in electricity demand after DST varies depending on the region of the country.

Figure 1.1. Average Hourly Electricity Demand Before and After the Spring 2004 DST Transition, Los Angeles



Detailed analyses were developed to account for daylight, weather, and other factors. Econometric models were used to predict the percentage changes in electricity demand (by hour) that would potentially occur in the extended DST periods in March and November.

To better identify the impacts of the DST for different hours of the day, a normalization procedure for electricity demand was developed. The normalization procedure accounted for effects of temperature and daylight shift, and utilized reference hours that were not affected by any change in DST. This normalization helped to detect changes in electricity demand caused by the natural increase (or decrease) in daylight over the course of several months, as well as the more abrupt changes that occur in a transition to or from DST. Details of the methodology are found in Section 3 of this report.

The predicted percentage changes in electricity use were estimated for the 12 regionally representative electric utilities and then used to calculate the electricity savings for each region of the country to determine an approximate magnitude of the potential national electricity savings. The utilities/cities analyzed for the potential impact of EDST are scattered throughout the country. Because some of the North American Electric Reliability Council (NERC) regions did not include a city that was analyzed (due to lack of available, high quality data), it was necessary to assign utilities to each region based on their location. Either the city assigned was near the region, or it was located in a similar spot within the time zone of the region to be analyzed. For example, the Midwest Regional Organization (MRO) had no cities within it that were evaluated. Rather than use Chicago, which was closest, Detroit was used, because it is located more in the western part of its time zone, a better match to the time zone of the MRO region. To better capture the variations that may occur across a region, the percentage potential impacts of DST from multiple utilities was averaged where data was available. The extrapolation methodology was vetted with the Department of Energy's Energy Information Administration (EIA) and other expert analysts.

Marginal costs at the utility level were used to identify the likely fuels that were being consumed by the utility to generate electricity at those hours of the day where EDST is expected to have an impact. In this manner, the potential total energy savings by fuel type were estimated.

1.6 Organization of the Report

Following this section, in Part 2, is a detailed description of the technical approach and analysis. Part 3 provides background on DST and highlights of previous DST studies.

Part 2 is organized into three sections. Section 2 describes the approaches considered for the analysis, while Section 3 presents the details on how the electricity savings are calculated for selected utilities across the country. Section 4 describes how the electricity savings are extrapolated to all the regions of the country to obtain an estimate of total primary energy savings.

Part 3 is organized into four sections. Section 5 provides background on DST and the EPAct 2005 extension. Previous studies on the energy effects of DST and other literature sources are reviewed in Section 6. Energy use by the different sectors is discussed in Section 7. Section 8 gives a qualitative description of non-energy findings from past assessments.

PART 2

DETAILED DESCRIPTION OF TECHNICAL ANALYSIS

2 Approaches Considered for Current Study

Based on review of the prior studies discussed in Part 3 and an assessment of available data sources, several approaches were considered at the outset of this study that were judged capable of generating estimates of the electricity savings associated with the proposed changes in the calendar for DST.

2.1 Statistical Analysis of Historical Electricity Use Across DST Transitions

Examining the pattern of electric-utility system demand immediately before and after the changes to DST is the most straightforward analytical approach to estimating the potential impact of DST. This approach was the basis for the 1975 study conducted by the DOT to estimate electricity savings potential from changes in the DST calendar. This approach was also used by the CEC as one validity check to their more complex econometric model of hourly system demand. The CEC did not rely on this approach for their complete analysis, because they wanted to employ a methodology that would estimate the *total* potential impact of DST (i.e., the savings already occurring under the current law), as well as generating savings estimates for DDST during the summer months. For purposes of estimating the potential impact of the incremental changes in the time period for DST under EPAct 2005, the before and after analysis appears to be a cost-effective approach and should yield credible estimates.

With a slight modification of the econometric specification employed by CEC, a very general specification of the following type may be considered:

$$\text{Load}_{ht} = \text{a}_h + \text{b}_h\,\text{Daylight}_{ht} + \text{c}_h\,\text{Weather}_{ht} + \text{d}_h\,\text{Daytype}_t + \text{u}_{ht} \qquad (2.1)$$

where:

h = hour of the day, 1 to 24

t = index for the day

Load_{ht} = the total system demand, megawatt-hours, in hour h of day t

Daylight_{ht} = a measure of percent daylight within the hour h of day t.

Daytype_t = pertains to whether day t is a weekday, Saturday, or Sunday

Weather_{ht} = a set of current and lagged weather variables, with possible transformations to represent nonlinear effects

u = a random disturbance term

This equation would be estimated separately for each interval of the day as defined above. The regression approach involves the estimation of Equation (2.1) for days approximately one month before and after the DST change. An estimation period of that length can be expected to provide sufficient information to provide robust estimates of the coefficients for the Daylight variable. A longer estimation period may bias the daylight coefficients, because they may then include seasonal changes in demand (e.g., water heating) or household activities (e.g., increased youth sports activities).

In the CEC methodology, this equation was estimated separately for each hour of the day. Some reduction of the number of regression models can be achieved in several ways. One method would be to group hours across the day into some distinct categories. For example, the morning hours between 6 a.m. and 8 a.m. might be collapsed into a single morning variable.

A second method retains the use of hourly data in the statistical analysis, but estimates the models only for hours around which the percentage of daylight changes over the historical time period. The potential impact of a shift to DST in the spring is expected to show up primarily in statistically significant values for the b_h coefficients corresponding to the hours with increased daylight in the early evening (and in the morning hours that have less daylight immediately after the shift to DST). It is during these periods in the spring when additional daylight in the evening is expected to have its greatest potential net impact on the system demand, because the need for electric lighting is delayed (and, perhaps, more outdoor activity reduces miscellaneous demand – e.g., less television viewing).

This study employed this second method, making the estimation process considerably less complex than that used by CEC. It does not involve separate estimates for every hour of the day, nor the construction of elaborate weather variables. The premise in this study was that this more modest approach would be sufficient to capture the incremental changes in the DST calendar enacted by EPAct 2005.[8]

2.2 Examination of Household Metered Data for Lighting and Miscellaneous Appliance Loads

In the mid-1980s, the Bonneville Power Administration (BPA) undertook a very large project to collect metered end-use consumption data for a large number of residential and commercial buildings in the Pacific Northwest (End-Use Load and Consumer Assessment Program, ELCAP). The published report for residential buildings shows both the monthly and hourly patterns of lighting and miscellaneous plug demand (or "convenience" loads). The monthly data clearly reveal the saddle-shaped pattern of electricity use for lighting that peaks in the winter and falls to its lowest point in June and July. On an hourly basis, the graphs show the morning peak use, as well as the much higher consumption levels during the evening hours for lighting and miscellaneous demand. The graphs also illustrate the quite different hourly profiles of electricity use between weekdays and weekends.

The ELCAP data provide time profiles for other end uses, some of which share similar behavior as lighting and plugs. For example, cooking and dishwashing also show morning and evening peaks. The change to DST could be expected to change the timing of the peak demand for some of these other uses (e.g., cooking later in the evening), but may have negligible potential impact on total consumption. We would expect actual *energy* savings to occur primarily for the lighting

[8] While no formal testing of this proposition was feasible for this study, the estimated savings are consistent with those obtained by the CEC for California. This topic is addressed briefly in the next section.

and miscellaneous demand category. In addition to increased daylighting, we might also expect some substitution of activities such as home computing and entertainment by outdoor activities (jogging, walking, gardening, etc.).

While the published report of residential energy use from ELCAP contains a large amount of graphical information, its use for estimating the potential impact of DST is compromised. The graphics in the report were based on data collected during the period September 1984 through May 1988. Unfortunately, the date for DST was changed from the last week in April to the first week in April, effective in 1987. That implies that graphics for monthly and hourly profiles are based on different schedules of DST over the time period.

ELCAP data for individual residences are still available in computer databases and can be accessed and downloaded to a spreadsheet format. However, this information requires some cleaning/verification and aggregation, as well as mapping to hourly weather data. Useable data exists for approximately 300 homes in the study. The ELCAP data may offer valuable insight as to how to isolate the potential impact of the DST schedule changes on lighting and miscellaneous demand.

The 2001 CEC study also made use of hourly metered residential data from the Hourly Electric Load Model (HELM) to corroborate its regression-based estimate of potential impact on peak evening demand. As noted by CEC, the HELM data also dates back to the mid- and late 1980s. The CEC report suggests that more recent data to support HELM was forthcoming, but at the time the current study was undertaken the availability of such data was not certain.

Of course, an issue of concern with the use of 20-year-old metered data is that lifestyles may have changed to a degree that would cast doubt on any estimates derived solely from this approach. The national Residential Energy Consumption Surveys (RECS), conducted by EIA, have shown that the demand associated with miscellaneous appliances and small equipment has grown faster than any other end use. Unfortunately, there is little information about the hourly profile of these demands that would indicate that a shift in the DST calendar would have any significant potential impact on this use. Presumably, some of this demand is associated with parasitic functions such as time clocks, battery charging, and related uses and, thus, would seemingly not be affected by DST. How much of the increased electricity use associated with personal computers and electronic games occurs during the late afternoon and early evening hours? Would more daylight cause substitution away from these activities toward outdoor activities? These are questions that cannot be answered without more recent end-use metering studies or by detailed survey information.

A trend in the opposite direction is the increased number of meals consumed outside the home—reducing cooking and, presumably, lighting use in residences in the early evening hours. Of course, some portion of the energy use associated with these activities is simply transferred to the commercial sector, along with increased gasoline consumption. Whether people would tend to do more outdoor cooking or, rather, be more comfortable in traveling in the daylight to a restaurant is an empirical question.

2.3 Building Simulation Analysis with Daylighting

The third approach considered would be to develop the potential impacts of DST changes solely from building simulations, weighted to represent the total stock of buildings in the United States. One might expect some potential impact on commercial-building lighting demand from the DST extension into November (with sunsets in the northern portion of the United States overlapping with commercial occupancy schedules).

Some activity is currently being funded by DOE's Office of Energy Efficiency and Renewable Energy (EERE) to more fully explore the potential of daylighting in commercial buildings. If simulation models have been built as part of that effort, they could be potentially adapted to perform this analysis. Unfortunately, the potential impacts depend heavily on the assumptions about the current application of daylighting in various types of commercial buildings. In ideal conditions, lighting controls are used to continuously adjust electric lighting to meet specified levels of illumination along the building perimeter. With a (one-hour) shift in daylight availability, the models can predict the magnitude of the reduced requirements for electric lighting. Again, however, some quantitative assessment of the amount of daylighting that is currently used is required before a credible estimate of the potential impact of a longer DST regime can be developed.

Conceptually, this same approach can be followed for residential buildings. It is not known whether any simulation studies of the residential sector have looked at this issue. Daylighting in the late afternoon in homes is a function of people's activity (e.g., occupancy of various rooms), typical window configurations, and preferred lighting (illumination) levels. Privacy concerns in the late afternoon (dusk) may also potentially impact the daylighting availability to some degree (by pulling shades) for windows facing the street or close to neighbors.

Rationale for Chosen Approach

While the latter two approaches may be able to provide some key insights as to how DST influences the behavior of various subgroups of electricity consumers, they were judged as not being able to efficiently provide a credible first-order estimate of savings from a change in the DST calendar. DST potentially impacts electricity consumption in both commercial and residential buildings, as well as street and outdoor lighting. Either of the latter two approaches would require a number of assumptions to develop an estimate of national electricity savings. Accordingly, the approach based upon a statistical analysis of hourly system loads [Approach (2.1)] was judged to yield the most reliably predictive measures of EDST potential impacts, within the available schedule and budget for this assessment. The method is described in more detail in Section 3.

3 Electricity Impacts for Selected Utilities

3.1 Methodology

This section presents the electricity savings estimates for selected utilities around the United States and discusses the specific methodology used to develop the estimates. Estimates presented should be viewed as expected value of the potential savings, with some level of uncertainty associated with the estimates. Following Approach (2.1), as described in Section 2.1, data are required to construct three primary sets of variables: hourly system demand for specific utilities, weather variables, and daylight variables. Before turning to the specific regression models that were employed in the analysis, the process by which these variables were developed is presented.

3.1.1 Data Sources and Construction

Hourly System Loads

To develop a robust estimate of the *national* savings associated with the change in the DST calendar, utility data from all regions of the United States were collected. Hourly system data is provided by many utilities to the Federal Energy Regulatory Commission (FERC) and posted on the FERC Web site.[9] The Web site contains data for multiple years, but is of varying completeness. While many utilities have provided hourly system load and marginal cost (system lambda) for every hour of each year, others have submitted more limited data.

A portion of the utility energy load data was collected from other sources. Information for several regions in New England (Northeast Massachusetts-Boston and Rhode Island) was available from ISO New England.[10] Other data were provided by some utilities through special request, including one Texas municipal under conditions of confidentiality.

Table 3.1 lists the utilities used in this analysis, along with the cities for which weather data were collected. The specific choice of utilities depended on several factors: 1) convenient availability of hourly load data, 2) a judgment as to whether the utility might adequately represent a significant portion of a region, and 3) reasonable geographic compactness, so that the construction of the representative daylight and weather variables was necessary for only a single location (city). A major utility in Indiana was chosen where DST has not been observed, and where some valuable insight may be gained by comparing the behavior of its system electricity demand to utilities in surrounding states. That rationale, in part, was behind the inclusion of the utilities serving Detroit, Chicago, and Dayton.

Weather Data

Weather information for specific locations is taken from the Local Climatological Data (LCD) files constructed by the National Climatic Data Center (NCDC). Hourly weather data for each month for about 800 locations in the United States are available from this source. Text files for

[9] The utility data is transmitted via Form 714 - Annual Electric Control and Planning Area Report. The address of the FERC Web site is http://www.ferc.gov/docs-filing/eforms/form-714/data.asp.
[10] The Web site for ISO-New England is http://www.iso-ne.com/markets/hstdata/znl_info/hourly/index.html.

the months of March, April, October, and November were downloaded from the NCDC Web site.[11]

Table 3.1 Electric Utilities Considered in Study

Utility	Representative City for Weather Data	Source of Utility Load Data
N.E. Massachusetts Region of ISO-NE	Boston	ISO New England
Commonwealth Edison of New York	New York (La Guardia)	FERC Web site
Detroit Edison	Detroit	FERC Web site
Dayton Power and Light	Dayton	FERC Web site
Indianapolis Power and Light	Indianapolis	Provided by Utility
Commonwealth Edison	Chicago	FERC Web site
Florida Power and Light	Miami	FERC Web site
Georgia Power	Atlanta	FERC Web site
Texas Municipal Utility	(withheld)	Provided by Utility
Public Service of Colorado	Denver (Centennial Airport)	FERC Web site
Los Angeles Dept. of Water and Power	Los Angeles	FERC Web site
Portland General Electric	Portland, OR	FERC Web site

Key variables in each file are temperature, humidity, cloud conditions, wind speed, and precipitation.[12]

In this assessment, the statistical analysis considered only a single weather variable—the outdoor temperature. The temperature variable (T*) is defined as weighted average of temperatures (T) in the previous two hours and the hour concurrent with the system demand. Specifically, T* is defined as

$$T^* = 0.2 * T + 0.5 * T(-1) + 0.3 * T(-2) \tag{3.1}$$

The temperature readings are typically recorded during the last 10 minutes of the hour (e.g., for Boston, the weather files show temperature readings at 54 minutes past the hour for all hours of the day). Thus, the relatively small weight on the concurrent hour seems appropriate given the lag in a building's space-conditioning system to changes in outdoor temperature. While more complex lag patterns are used in demand-forecasting models, this specification was deemed sufficient to adequately isolate the potential impact of the variable of interest—the percentage of daylight in the hour.

[11] The NCDC Web site for this information is http://cdo.ncdc.noaa.gov/ulcd/ULCD.

[12] Several processing steps were required to make this weather data usable for the statistical analysis. The LCD files include many observations within each hour that do *not* contain the temperature. Excel's advanced filter capability was used to include only those 24 hourly observations that contain temperature readings (typically recorded during the last 10 minutes of the hour). Only "unedited" LCD (labeled as ULCD) files on the NCDC Web site contain hourly or sub-hourly observations. It is not unusual for temperature data from these files to be missing for one or two hours in a particular month. In these cases, temperature values were interpolated from adjacent hours.

Daylight Variables

Following the approach used by the CEC, the daylight variables were constructed as the percentage of daylight within a given hour. Sunrise and sunset times were taken from the sunrise/sunset computer program provided by Fly-By-Day Consulting Inc.[13]
In addition to the sunrise and sunset times, the online program also provides beginning and ending times for what is termed *civil twilight*. Formally, the period of civil twilight is defined as the moment in the morning or evening when the sun is at a depression angle of 6 degrees below an ideal horizon. According to the Fly-By-Day Consulting Web site, the illumination at the beginning or end of civil twilight is such that large objects can be seen, but no detail is discernable. The length of civil twilight varies by time of year and latitude. For the U.S. locations in this analysis, civil twilight typically ranges between 25 and 30 minutes in the first part of April.

The CEC study included variables for the both daylight and twilight. That study involved observations across the year, and so the differential potential impacts from daylight and twilight may be discernable in the statistical analysis. For the study—with emphasis on the periods immediately before and after the DST transitions—this approach was judged to not be feasible. For the analysis here, it was assumed that the beginning or end of effective daylight includes one-half of the twilight period.

Table 3.2 illustrates the construction of daylight times for Chicago during the month of April (2004). On April 3, sunset occurred at 6:19 p.m. (18:19), with civil twilight lasting another 28 minutes. Using 50 percent of the civil twilight period, effective daylight is assumed to end at 6:33 p.m. (18:33). Thus, the value of the daylight variable for the 6 to 7 p.m. hour is 0.55 (33 minutes/60 minutes). DST starts the next day, shifting the end of daylight to 7:34 p.m.

Note that the natural seasonal change increases evening daylight by roughly one-half hour during the month of April. As will be discussed later in this report, the methodology to estimate the potential impact of a DST calendar change must also take this natural phenomenon into account.

3.1.2 Model Specifications

The general specification defined in Equation (2.1) in Section 2.1, provides a starting point for the empirical implementation of the statistical methodology. As the study progressed, two separate variants of that general specification evolved; both compare the behavior of hourly energy demand before and after the DST transitions.

[13] The Web site for this online computer program is http://www.mindspring.com/~cavu/sunset.html.

Table 3.2 Construction of Beginning and Ending Times for Effective Daylight: April 2004 for Chicago

April	Civil Twilight - Start	Sunrise	Sunset	Civil Twilight End	Begin Light	End Light
1	5:04	5:32	18:16	18:44	5:18	18:30
2	5:02	5:30	18:17	18:45	5:16	18:31
3	5:00	5:29	18:19	18:47	5:14	18:33
4	5:59	6:27	19:20	19:48	6:13	19:34
5	5:57	6:25	19:21	19:49	6:11	19:35
6	5:55	6:24	19:22	19:50	6:09	19:36
7	5:54	6:22	19:23	19:51	6:08	19:37
8	5:52	6:20	19:24	19:52	6:06	19:38
9	5:50	6:19	19:25	19:53	6:04	19:39
10	5:49	6:17	19:26	19:55	6:03	19:40
11	5:47	6:15	19:27	19:56	6:01	19:41
12	5:45	6:14	19:28	19:57	5:59	19:42
13	5:44	6:12	19:29	19:58	5:58	19:43
14	5:42	6:11	19:30	19:59	5:56	19:44
15	5:40	6:09	19:32	20:00	5:54	19:46
16	5:39	6:08	19:33	20:02	5:53	19:47
17	5:37	6:06	19:34	20:03	5:51	19:48
18	5:35	6:04	19:35	20:04	5:49	19:49
19	5:34	6:03	19:36	20:05	5:48	19:50
20	5:32	6:01	19:37	20:06	5:46	19:51
21	5:31	6:00	19:38	20:07	5:45	19:52
22	5:29	5:58	19:39	20:09	5:43	19:54
23	5:28	5:57	19:40	20:10	5:42	19:55
24	5:26	5:56	19:41	20:11	5:41	19:56
25	5:24	5:54	19:42	20:12	5:39	19:57
26	5:23	5:53	19:43	20:13	5:38	19:58
27	5:22	5:51	19:45	20:14	5:36	19:59
28	5:20	5:50	19:46	20:16	5:35	20:01
29	5:19	5:49	19:47	20:17	5:34	20:02
30	5:17	5:47	19:48	20:18	5:32	20:03

Energy Demand vs. Temperature Specification

The first specific approach looks at the change in the actual system energy demand (load) in the key hours before and after a DST transition. The choice of specific hours to model depends on the location of the utility within its time zone. Typically, the hours modeled varied between those ending between 6 p.m. and 9 p.m. (hours 18 through 21).[14] The model specification used in this approach was very straightforward:

$$\text{Load}_{ht} \;=\; a_h + b_h\,\text{Daylight}_{ht} + c_h\,T^*_{ht} + u_{ht} \qquad (3.2)$$

[14] For the remainder of this report, some labeling of hours will conform to a 24-hour clock. By convention, hour t is one which *ends* at time t. Thus, for example, hour 19 designates the hour between 6 p.m. and 7 p.m.

where

h	= hour of day, *clock* time,
t	= index for day
$Load_{ht}$	= total utility load in MW during the hour[15],
$Daylight_{ht}$	= percentage of daylight during hour h of day t,
T*	= weighted current and lagged temperature defined above,
u	= random disturbance term
a_h,b_h,c_h	= model coefficients that are specific to each equation for hour h

It should be emphasized that the specific hour of the day for which the model is estimated is in terms of clock time—not Standard Time. The pattern of hourly energy demand is influenced by typical social schedules (i.e. work and school schedules that are typically invariant to DST), weather, and daylight. As the CEC analysis shows (Figure 6.2 in Section 6.4), the pattern of energy demand is generally more strongly influenced by social schedules than by weather.[16] Thus, the approach here is to compare the loads before and after the DST transitions at the same clock hour of the day, with the aim of adjusting for changes in temperature to more accurately assess the independent effect of daylight.

The application of this particular model was restricted to examine the behavior of system demand only for weekdays. The levels and hourly patterns of system energy demand are very different on Saturday and Sunday as compared to weekdays. No meaningful statistical comparisons before and after the DST transition can be made just for weekend days. While the differences in energy demand for Saturday and Sunday can be handled via dummy variables in the regression models, it is not clear whether interactions between these day types and other variables should be included. Thus, to simplify the modeling work, only weekdays were included in this particular specification. Moreover, as will be shown below, the inclusion of the weekend days would unnecessarily complicate the transparency of any graphical comparisons.[17]

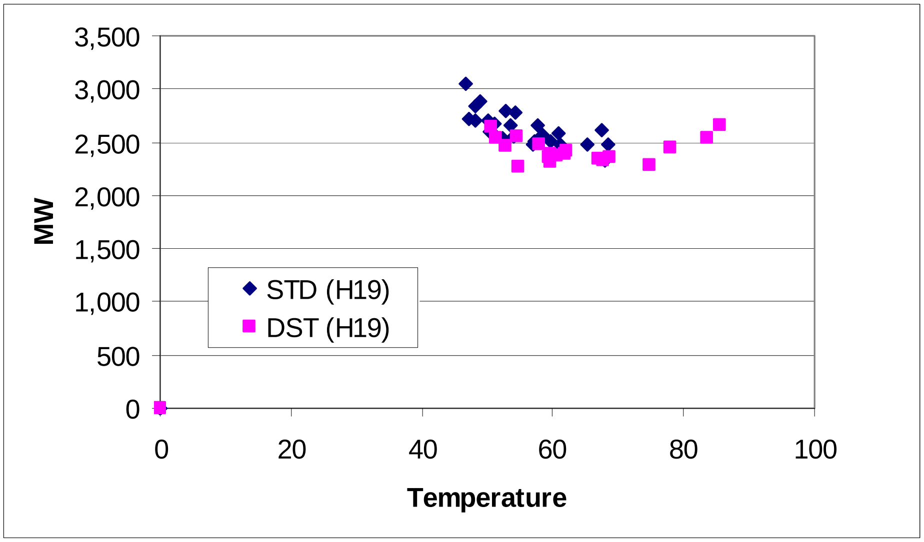
The importance of accounting for temperature varies across utilities. In the northern portions of the United States, the prevalence of electric space heating influences the need for this adjustment. Figure 3.1 shows, for example, how the demand for Portland General Electric increases with lower temperatures in the 6 to 7 p.m. time frame. Hourly demand is plotted for weekdays in March and April 2004. The figure appears to show a strong negative relationship between demand and temperature, with days with DST showing consistently lower demands. Based on casual inspection, a simple linear relationship between demand and temperature does not hold where temperatures exceed approximately 65 degrees. In such cases, an improved specification would substitute temperature with a heating degree hour (HDH65) measure where

$$HDH65 = (65 - T^*) \text{ for } T^* < 65, 0 \text{ otherwise}$$

[15] To avoid any confusion, all the loads used in the analysis (available through FERC) are the *integrated* hourly loads; i.e., they are, in essence, the average load during that hour.
[16] One must caveat this statement in that the California study uses only California data. The plots of the hourly demands for other locations shown below, however, generally support this supposition.
[17] As will be discussed below, the second variant of the approach was the basis for the final statistical results. In that approach, weekend days were included in the model.

The figure also shows four days with temperatures above 70 degrees where some cooling may affect the total system demand. In this case, a more robust estimate of the potential impact of temperature (and daylight) is most expeditiously achieved by omitting those observations from the regression model.

Figure 3.1. Demand vs. Temperature for Portland in Hour Ending 7 P.M., Spring 2004



Following the general approach of the CEC study, the equations for the relevant hours were estimated as a system. For this model, the temperature response is typically assumed to be the same during each of these hours, and so the coefficients c_h in Equation (3.2) are restricted to be the same across all of equations in the system.

Normalized Load Specification

To satisfactorily estimate the potential impact of daylight, the specification employing the temperature variable works best when the range of temperatures is similar before and after the DST transition. For some locations, this situation was not observed in a number of the data sets. Moreover, because the spring change to DST can involve periods in which heating and cooling are both observed, it complicates the process of normalizing for different hourly temperatures.

After plotting the hourly load for a number of utilities, it became clear that most of the potential impact of DST is concentrated in the evening hours—primarily between hours ending at 6 p.m. through 9 p.m. In essence, DST is reflected by a change in the hourly profile of energy demand during these hours. This change in the hourly profile—a change in the relative demands from one hour to the next—appears to be largely independent of average temperature during that period. With that notion, a second general specification can be viewed as a modification of the “Equivalent Day Normalization” approach employed by the 1975 U.S. DOT study. In this case, a reference energy demand for the evening is defined for hours that always fall either into *full* daylight or into *no* daylight (full darkness).[18] Specifically, the evening reference demand (or load) (ERL) is defined as average load of the hours ending at 3 p.m., 4 p.m., 10 p.m., and 11 p.m. (hours ending at 15, 16, 22, and 23 on a 24-hour clock). Normalized loads for the intervening hours, h, are then defined as the following ratios:

$$\text{Lnorm}_{ht} = \text{L}_{ht} / \text{ERL}_{t} \quad h = 17, 18 \ldots 21 \text{ for day } t \tag{3.3}$$

As the next subsection will discuss in detail, DST results in a shift of the temperature profile with respect to clock time, leading to higher temperatures during the evening hours.[19] This shift also systematically changes how the average temperature varies from one hour to the next during these hours of interest. To account for these changes, a normalized temperature variable was constructed along the same lines of the normalized demand. For the evening hours, this normalization was made in terms of absolute temperature differences in each hour from the *average temperature* (using the T* transformation) defined by the four selected "uninfluenced" hours—again hours ending 3p.m., 4 p.m., 10 p.m., and 11 p.m. Defining this average temperature as the evening reference temperature (ERT), the normalized temperature difference in hour *h* of day *t* is then defined as:

$$\text{Tdiff}_{ht} = \text{T*}_{ht} - \text{ERT}_{t} \tag{3.4}$$

This use of the normalization was judged to not have the same complexity in dealing with the interaction between temperature and day types. Thus, to reflect the DST potential impacts for Saturday and Sunday, it was assumed that these days could be handled via dummy variables to account for differences in the energy demand profiles between weekend and weekdays. After adding the day type and temperature variables, the final specification becomes:

$$\text{Lnorm}_{ht} = \text{a}_{h} + \text{b}_{h}\,\text{Daylight}_{ht} + \text{c}_{h}\,\text{Sat} + \text{d}_{h}\,\text{Sun} + \text{e}_{h}\,\text{Tdiff}_{ht} + \text{u}_{ht} \tag{3.5}$$

To detect changes in demand profiles in the early morning hours, a similar approach was followed. Again, a base period load was defined—in this case, an average load for hours ending at 4 a.m., 5 a.m., 9 a.m., and 10 a.m. Normalized loads are then defined, as above, for the hours ending between 6 a.m. and 8 a.m.

To help illustrate some advantages of using this specification, the 6 p.m. to 7 p.m. hourly data for Boston (Spring 2004) is plotted in several ways. Figure 3.2 shows demands versus temperatures for this data set. While it is clear that at the same temperature the energy demand is lower in daylight time as compared to the same clock hour in Standard Time, it is not readily apparent

[18] In the 1975 DOT Study, the hours defining the reference load were termed "uninfluenced hours." Hours where daylight effects are expected to occur were termed "influenced" hours. Influenced hours in the DOT study were very broad: 4 a.m. through 10 a.m. in the morning, and 3 p.m. through 10 p.m. in the evening. All other hours were lumped into a single category of uninfluenced hours. One reason for the broad range of influenced hours is that DOT considered large changes in the DST calendar (e.g., February through November) that would make sunrise and sunset times differ substantially from those that result from the current law.

[19] More accurately, of course, clock time shifts with regard to solar time and a typical profile of hourly temperatures. Because the loads are being compared for the same clock time, before and after a DST transition, a consistent treatment suggests an impression that temperature has shifted with respect to the clock.

from the figure how exactly to handle the temperature variable in the model. As for Portland, it makes sense to drop the observations for T* > 70. However, inspection of the remaining data suggests that the temperature response may not be linear across the range of observed temperatures. That issue might only be resolved by trial-and-error testing of alternative temperature specifications or pooling data from earlier years. In either case, developing case-specific models for each location was infeasible in this assessment.

Figure 3.2. Demand vs. Temperature for Boston in Hour Ending 7 P.M., Spring 2004

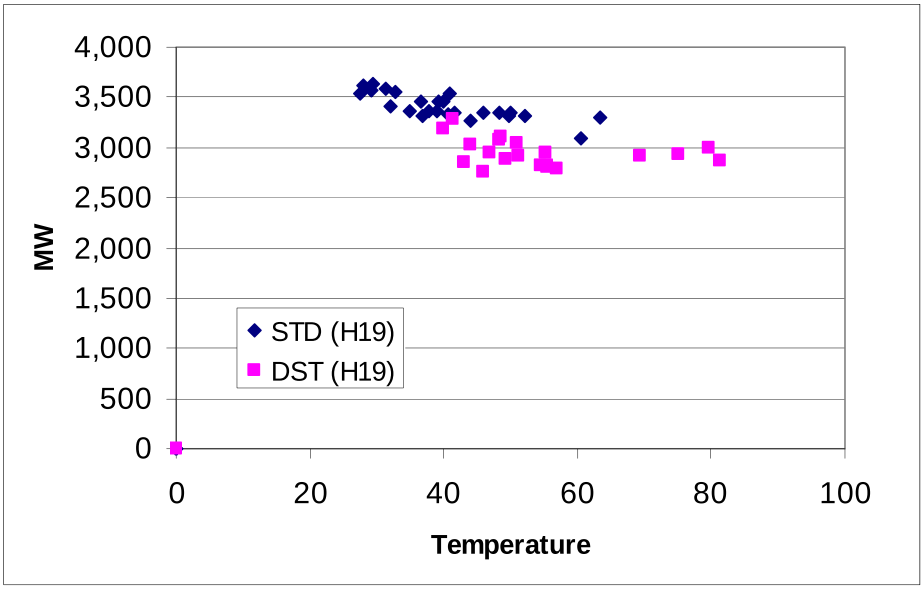


Figure 3.3 shows a plot of the normalized load for this same time period. This plot clearly shows that, with the exception of just four days in April, the variation of the *normalized* load in this hour is quite stable. This occurs in spite of the fact that the observed range of temperatures for these two months at this hour is *more than 50 degrees*. Moreover, potential impact of increased daylight is readily observable in this specification. Not only does the plot show the sharp drop in electricity use after DST (April 4), but it also shows some reduction in the energy demand from natural increase in daylight before that date.

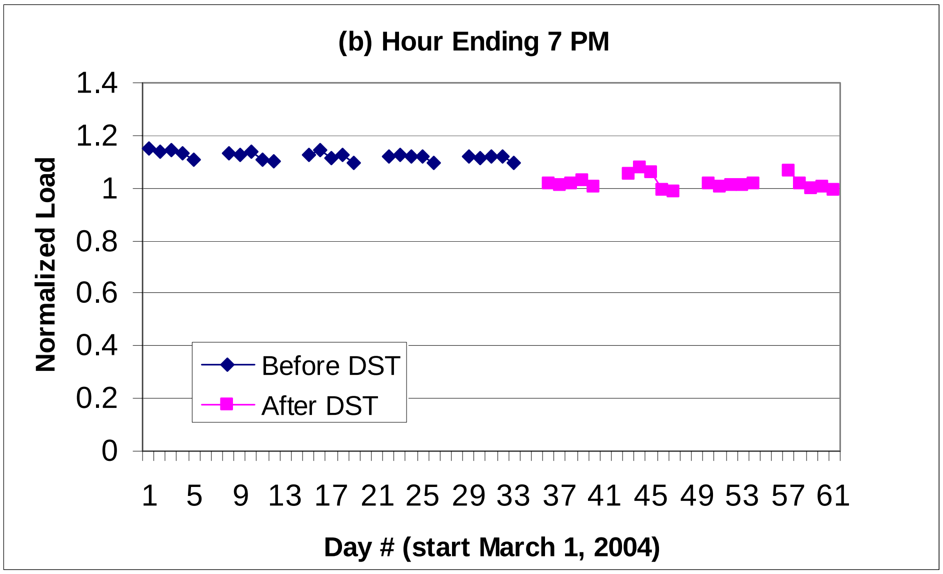
The normalized load specification is viewed to offer some distinct advantages over modeling the absolute demand:

- Plots offer better resolution (i.e., a more robust data "signature") of the relative reductions in the demand for specific hours and can be visually correlated with daylight variables.[20]
- The potential impact of temperature variation from one day to the next is mitigated, and the need for complex transformations or adjustments of the temperatures is precluded.

[20] As a side benefit, the plots also help identify any data anomalies in the demand data. While the labeling of any data point as an anomaly is subjective, in only a couple of data sets were one or two demands observed that clearly did not follow the typical patterns of the remaining data. The issue of data quality was a concern in the 1975 DOT study, but electronic recordkeeping in today's utilities eliminates that as a concern.

- Any interaction of temperature and day of the week is likely to be smaller.
- The relative potential impacts of the daylight and temperature variables can be readily compared across locations by comparing the values of the estimated coefficients.

Figure 3.3. Normalized Weekday Loads for Boston in Hour Ending 7 P.M., Spring 2004



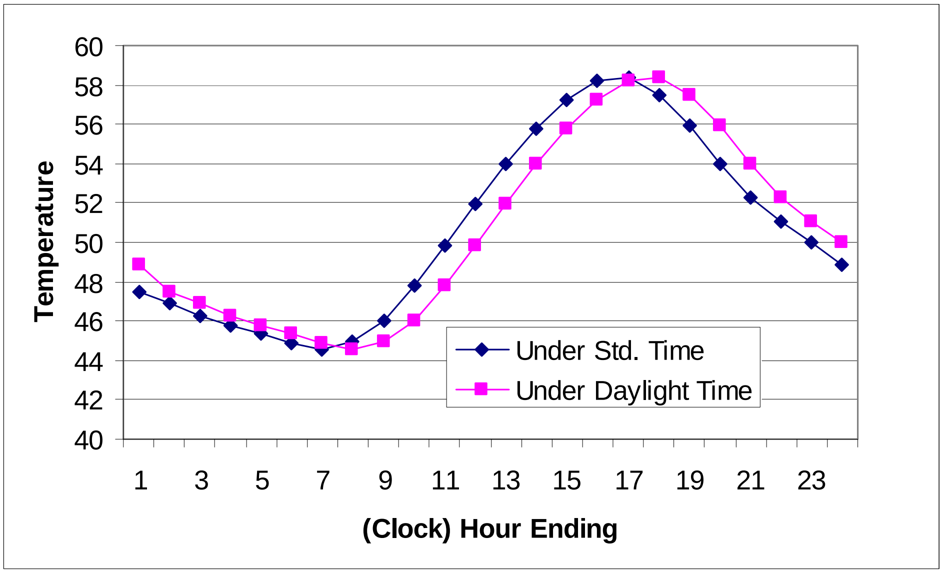
3.1.3 DST and Hourly Temperature

A robust method for disentangling the effects of daylight and temperature to accurately estimate the potential impact of DST must take into account the several ways that temperature can affect the total system energy demand. In the first place, it should be reiterated that any analysis of demands before and after a DST transition must seek some way to hold temperatures constant. Thus, the weekly variability of temperatures in most areas in the United States makes any single year's comparison of system demand before and after a transition practically meaningless. Even averaging over a period of years is problematic, because temperatures normally increase over the course of spring and decline during the fall. Thus, in locations where heating is still dominant in the spring, the effects of additional daylight will be overstated by a naïve comparison of demands; and vice versa in locations where cooling is prevalent at these times of the year. All of this may seem common sense, but it is not always clear from prior studies that an adequate adjustment has been made for this type of temperature change.

A second influence of DST is more subtle in that it impacts the intra-day profile of temperatures with respect to clock time. It is often remarked that DST does not provide any additional daylight over the day, but just shifts it to later in the day. That same notion applies to daily rise and fall of temperature; DST shifts the temperature peak to later (clock hour) in the day. However, the important point is that, just as there is no more total daylight with DST, DST also does not change the average daily temperature. If there really is any substantial effect on overall electricity use from such a shift in the hourly temperature profile, it must result from differential impacts of temperature on space conditioning use over different hours of the day.

Figure 3.4 illustrates this shift by the use of monthly average temperatures for Portland, OR for March (2004 data). By shifting the clock forward by one hour under DST, temperatures at the same clock hour are lower by one to two degrees from mid-morning through late afternoon. In the evening, this situation is reversed, with warmer temperatures occurring in the evening (by up to two degrees) and extending throughout the night.

Figure 3.4. Hypothetical Shift in Temperature Profile Under DST – March 2004 Average Temperatures in Portland, OR



As discussed briefly in earlier sections, the 2001 CEC study included an ambitious attempt to account for the differential impacts of temperature over the different portions of the day. The CEC attempted to measure the total impact of DST, implied by both the current implementation of DST during the April-October period, as well as substantial proposed *changes* in the DST calendar (including shifting the clock forward another hour during the summer). As part of this work, CEC needed to pay close attention to precisely how temperature was modeled for different hours of the day. However, at the outset of this study, and as mentioned in the previous section, it was concluded that developing a complex model of temperature sensitivity for all hours of the day was beyond the scope of time or resources for this assessment.

Nevertheless, in the current study, the conclusion was reached that for the specific hours where changing daylight conditions would affect electricity use (under EPAct 2005), there still needs to be a credible method separating out the effects of temperature and daylight. Given that temperature and daylight affect somewhat independent end uses in buildings (space conditioning and lighting), the simple linear regression model specified in Equation (3.2) seems adequate to that task.

Given the estimated potential impact of daylight on electricity use, one is then left with the question of whether the DST-induced shift in the 24-hour profile of temperatures, as illustrated in Figure 3.4, has any significant additional potential impact on total electricity use. While the approach above may yield the response to temperature for the specific hours of day modeled, it does not explicitly account for the remaining hours of the day. The premise of the current study is that, to a first approximation, the potential impact of this temperature shift is likely to be very small. With that assumption, any temperature-related impacts in these (non-modeled) hours can be ignored because they are basically offset by temperature-related changes in the demand over the hours which DST is expected to have a potential impact.[21]

In part, this assertion is made on the first principles of the physics that fundamentally determine the amount of space-conditioning energy use in buildings. Under steady-state conditions, the space-conditioning thermal load for a building can be expressed as

$$TL = u\,(T_i - T_o) - I$$

where

TL	= Thermal load (measured in British Thermal Units), TL > 0 indicates heating load; TL < 0 indicates cooling load
T_i	= Inside temperature (thermostat setting)
T_o	= Outside temperature
I	= Internal heat gains from equipment and occupants plus the solar heat through the building's windows
u	= u-factor that characterizes the thermal integrity of the building walls, roof, and floors, as well as effect of air infiltration

When the outside temperature is sufficiently low, relative to the indoor temperature (after consideration of internal gains), heating is required (measured as a positive thermal load). Given the magnitude of the internal heat gain, the outside temperature need not exceed the thermostat setting before cooling is required (measured as a negative thermal load in this simple framework). High internal heat gains in many types of commercial buildings result in cooling demand when the outside temperatures is 10 or 15 degrees cooler than the desired indoor temperature.

In this simple model, one sees that as long as the desired internal temperature remains constant and that the space conditioning system reacts promptly to any change in outside temperature, then the response to a one-degree change in temperature, higher or lower, would be the same regardless of the time of the day. In this model, this constancy of the response is still consistent with the fact that space-conditioning demand would vary over the day, even if the outside temperature were constant. The time profile of internal gains (I) has an important independent effect on the space-conditioning energy use, particularly in commercial buildings. However, that variation would not affect the temperature *response*, as long as some amount of space conditioning is always required.

The actual temperature response of energy use in buildings is, of course, much more complicated than this simple model. Building temperatures are not constant, from either the use of thermostat

[21]As defined previously, the specific portions of the day during which the change in the DST calendar is expected to have a potential impact are hours ending 6 a.m. through 8 a.m. in the morning, and hours ending 5 p.m. through 9 p.m. in the evening.

setbacks (or cooling setups), or from the dead band feature in the thermostat that allows the internal temperature to float between an upper and lower setting. Buildings vary in the way they respond to normal hourly changes in temperatures over the day, as a result of their thermal "mass." An example would include a building with masonry walls where heat is stored and then released, a factor that slows the response of the space-conditioning system to changes in outside temperature. These and other factors will diminish the accuracy of this simple model to various degrees, depending on the building characteristics and the level and variation of temperatures over the day. Simulation modeling of a set of representative buildings would be able to provide some means of assessing the potential impact of these various factors. However, one should recognize that even simulation modeling has its limitations in addressing this question, because accurate information on how building occupants (both commercial and residential) control the indoor temperature is lacking.

With this last caveat in mind, the 1996 simulation study by Brian Rock at the University of Kansas may be relevant to this issue. While addressing only residential buildings, the simulations necessarily focus on the temperature shift induced by DST. While the article unfortunately provides no details about the results (change in energy use by either hour of the day or by region), the ultimate conclusion was that DST causes a negligible change in energy use across the United States.

The CEC modeling also suggests that the effect of this temperature shift may not be significant, particularly in the spring and fall. While Figure 6.2 in Section 6.4 indicates that there may be some slight increase in electricity use in the morning hours, there is no perceptible change in the mid-morning to late-afternoon hours. These are the (clock) hours over which the outside temperatures under DST would lower. Of course, one has to be guarded in extending this finding to other regions of the United States, where electricity use for space conditioning varies and where the climatic conditions differ.

To summarize, a full treatment of how the shift in the hourly profile of temperatures, induced by DST, affects space conditioning was beyond the scope of this assessment. Based on the notion that the *average daily* temperature does not change and the limited simulation and statistical evidence, the assumption is made that the overall potential impact on space conditioning is small in comparison to the effects on lighting (and appliance) use.

3.1.4 Econometrics

The estimation of all model parameters was performed in the EViews 5.1 software system. EViews is widely used in the academic and consulting community, and is actively maintained by Quantitative Micro Software (QMS). EViews has the ability to readily import and export data sets from Excel, which was the tool used to organize all of the model data. A separate EViews data set was developed for each utility for each DST transition and year.

As mentioned above, the sets of consecutive hourly models were estimated as systems. For the demand vs. temperature regressions, this treatment allowed the estimated temperature response to be restricted to the same value for each hour.

In the standardized demand model, this restriction on the temperature difference variables was not applied. In that case, there is no difference in the parameter estimates between the "system" estimates and single-equation estimates. However, in this case, there is the presumption that the estimates can be improved by taking into account the cross-equation correlations of the model errors. The Seemingly Unrelated Regression (SUR) technique was formulated to address this situation. The CEC employed this technique in their specification, employing a system of 24 hourly demand equations. This technique accounts for correlations in the residuals between closely related portions of the day, and can be expected to improve the statistical precision of the parameter estimates. EViews has a convenient feature to implement the SUR technique.

Many of the estimate models showed the presence of a moderate amount of serial correlation in their residuals. This result was not unexpected for daily and hourly electricity demand data. In predictive models of hourly demands, the academic and consulting world has developed sophisticated time-series techniques to deal with this issue. For this study, the major focus is in quantifying the influence of changes in daylight on the time pattern of utility loads—not short-term forecasting. Accordingly, when serial correlation was deemed to be sufficiently severe and to potentially affect the parameter estimates, a first-order autoregressive (AR) adjustment technique was applied in EViews.[22] Typically, however, this adjustment had only a minor effect on the coefficients for key variables of interest—the daylight variables.

3.2 Empirical Results

This section presents the results of the regression models of hourly demand and describes how electricity savings for each utility was estimated. The first subsection below details this process for Los Angeles. Los Angeles is selected as an example, because it shows relatively small variations in temperatures over the spring months. Moreover, it may be instructive to compare these results with those obtained by the CEC for all of California. In subsequent subsections, for the remaining locations analyzed, the presentation of results is more limited and emphasizes particular results that appear to be special for that utility or region.

3.2.1 Empirical Results for Los Angeles and Derivation of Electricity Savings

As cited in Table 3.1, the hourly demand data for Los Angeles are for the Los Angeles Department of Water and Power (LADWP). LADWP is the largest municipal electric utility in the United States.

Graphical Display of Data

Before discussing the results of the regression models, it is helpful to gain some basic familiarity—as can be shown graphically—with the behavior of electricity demand for March and April. The data shown are for 2004, the latest year available from the FERC Web site. Typically, the data were plotted in three ways: 1) average hourly demands for the several work weeks prior and subsequent to a DST transition, 2) demand vs. temperature before and after the DST transition for all weekdays in March and April (as in Figure 3.1 and Figure 3.2 above), and the normalized loads for various hours of the day.

[22] Generally, the adjustment was applied when two or more equations in the system showed Durbin-Watson statistics less than 1.5, when estimated by ordinary least squares (OLS).

Figure 3.5 presents the average hourly demands for a five-day workweek, two weeks prior to the start of DST (March 22 through 26); and the five-day workweek, just after the DST transition (April 5 – April 9). These particular weeks showed very similar average temperatures over these periods. The average hourly temperatures are plotted in Figure 3.6. While this comparison is from two separate weeks, the hourly profile in the second displays the shift with respect to clock time that was discussed in Section 3.1.3.

Figure 3.5. Average Hourly Demands Before and After the Spring 2004 DST Transition, Los Angeles

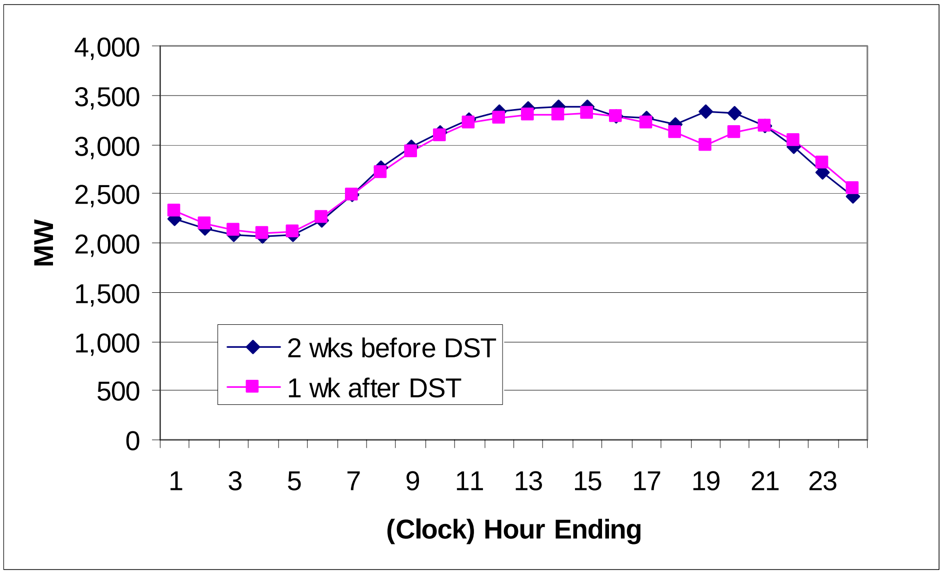
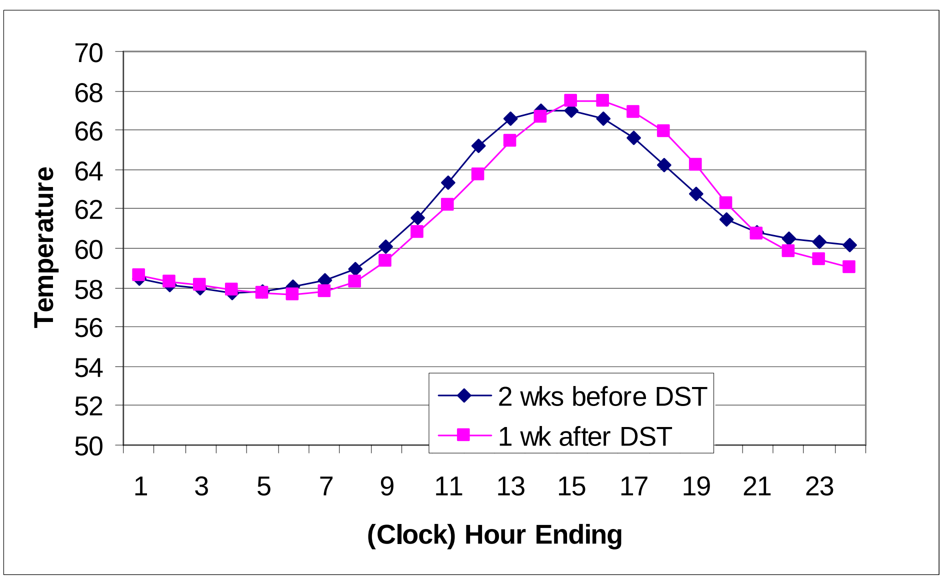


Figure 3.6. Average Hourly Temperatures Before and After the Spring 2004 DST Transition, Los Angeles



The plots clearly show the reduction in electricity demand in the evening hours in the week after the DST transition, with the potential impacts occurring in the hours ending at 7 p.m. and 8 p.m. The differences in demands in other hours of the day are negligible. There appears to be a small increase in the energy demand during the night time and early morning hours under DST, as well as some small reduction in the demands during the mid-day. The small increase in the early-morning hours may indeed reflect less daylight during these hours. Other changes could be the result of the temperature shift as discussed in Section 3.1.3 (assuming that significant portion of the demand is attributable to cooling in commercial buildings). Without further analysis, however, it is hard to infer too much from a comparison averaged over an entire week.

Figure 3.7 plots demand vs. temperature for four separate time periods for all weekdays in March and April 2004. The plots for the 6 a.m. to 8 a.m. period and the 9 a.m. to 5 p.m. period use average values for both demand and temperature for these periods. Consistent with the 24-hour plot in Figure 3.6, Figure 3.7a and Figure 3.7b show very little difference in the demand—before and after the DST transition—at the same temperature. That result can be contrasted to the behavior in the bottom two plots. With the exception of some hours with temperatures exceeding 80 degrees, the demand in the two evening hours displayed is distinctly lower at the same temperature after DST.

Figure 3.7a-d. Demand vs. Temperature for Four Time Periods in March-April 2004, Los Angeles

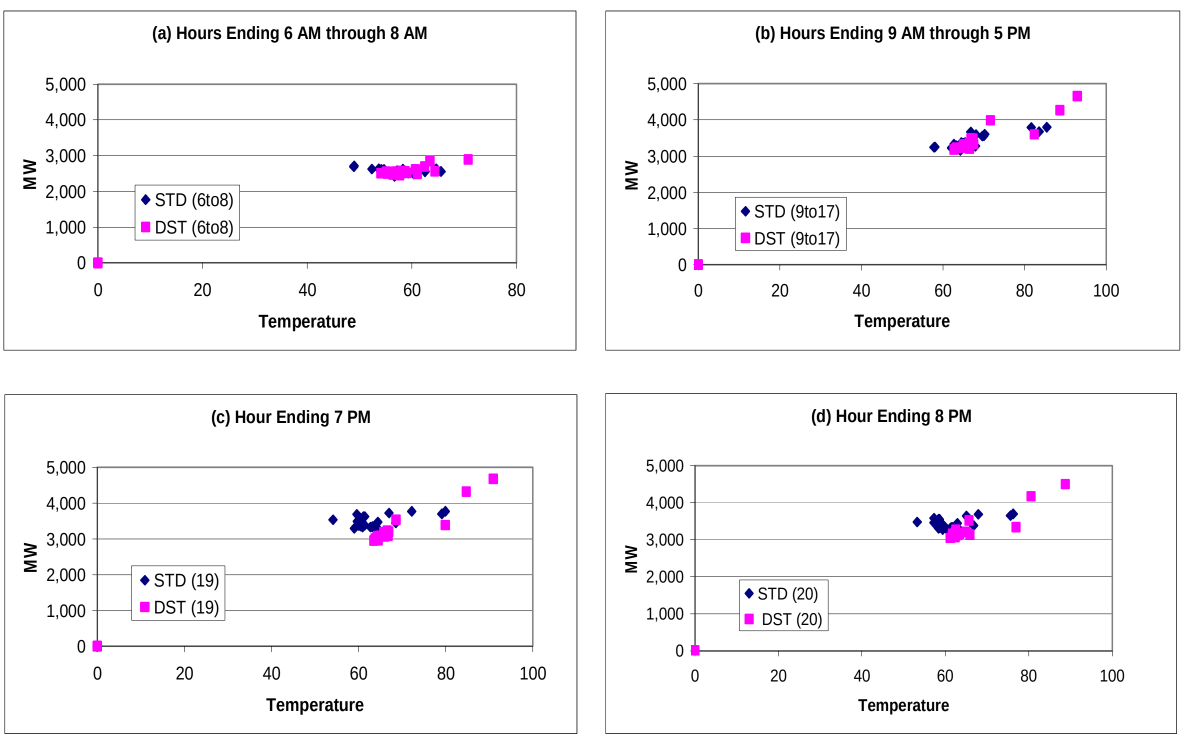
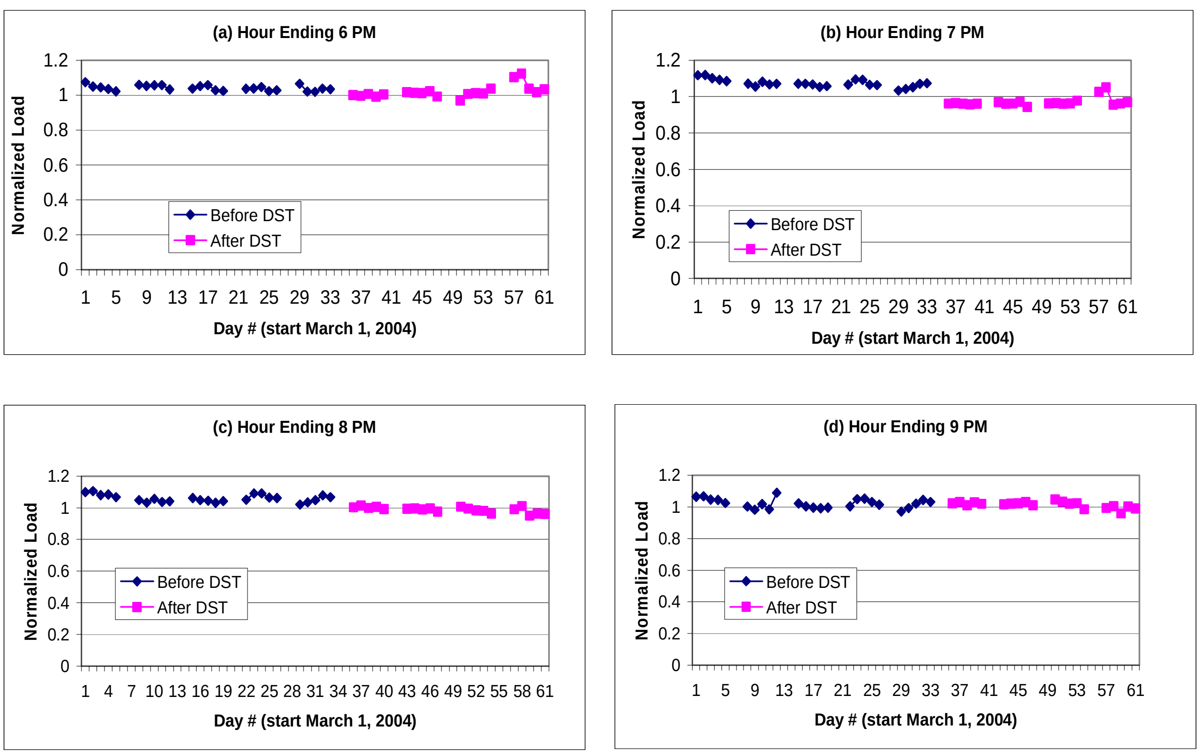


Figure 3.8 (a – d) displays the normalized loads for the evening hours ending from 6 p.m. through 9 p.m. The top right chart shows the normalized loads for the 7 p.m. hour. On April 3, the last day under Standard Time, the computed end of daylight was 6:30 p.m. The normalized

loads points are consistent with a gradual increase of daylight through much of March and then full daylight when EDST goes into effect. In the subsequent hour (ending at 8 p.m.), there is no daylight before April 4. On April 4, roughly 50 percent of the hour is in daylight and then increases slowly through April. While the trend decline is small, and there are some days that are off of the trend line, there is a perceptible reduction in the normalized load represented by the dark pink squares in the figure.

A close examination of Figure 3.8a shows that there also may be some decline in the normalized load for the hour ending at 6 p.m. Clearly, this decline is likely not due to the lack of daylight in this particular hour, although perhaps could be related to the low angle of sun at this time of the day and greater shading from other buildings and trees. The reduction may also be the result of behavioral factors. As more daylight falls into the 6 p.m. to 7 p.m. time frame, people may be prompted to begin more outdoor activities in the preceding hour. This behavior of the normalized load was observed for a number of utilities. In these situations, the daylight variable for the following hour was employed in the regression models.

Figure 3.8a-d. Normalized Loads for Hours Ending 6 P.M. through 9 P.M. in March-April 2004, Los Angeles



Regression Results

The specifications using the absolute load [(Equation (3.2)] and normalized load [Equation (3.4)] above as dependent variables were both estimated. For the reasons described above, the specification that uses the normalized load became the preferred approach during the course of the study. In Section 3.3.3, some comparisons of the electricity savings implied by the two specifications are shown for a number of utilities. In general, the predicted savings are reasonably similar. The parameter estimates for the normalized load specification for Los Angeles are shown in Table 3.3. The key coefficients of interest are those related to daylight variables. The estimated coefficient for the daylight variables for hours ending at 7 p.m. (hour 19) and 8 p.m. (hour 20) have high statistical significance, with t-statistics over 9 for both coefficients.[23]

Table 3.3. Regression Results for Normalized Load Model for Evening Hours, Spring 2004, Los Angeles

System: SYS1820ARSUR
Estimation Method: Seemingly Unrelated Regression
Date: 02/10/06 Time: 21:02
Sample: 2 61
Included observations: 61
Total system (balanced) observations 180
Iterate coefficients after one-step weighting matrix
Convergence achieved after: 1 weight matrix, 16 total coef iterations

	Coefficient	Std. Error	t-Statistic
Variables - Hour 18			
Constant (Hour 18)	1.0478	0.0116	90.2
Daylight19	-0.0429	0.0158	-2.7
Saturday	-0.0230	0.0063	-3.7
Sunday	-0.0323	0.0062	-5.2
Tdiff_18	0.0046	0.0013	3.7
AR coefficient	0.6115	0.0791	7.7
Variables - Hour 19			
Constant (Hour 19)	1.1235	0.0097	116.3
Daylight19	-0.1603	0.0130	-12.3
Saturday	0.0231	0.0056	4.1
Sunday	0.0235	0.0057	4.2
Tdiff_19	0.0043	0.0011	4.0
AR coefficient	0.5757	0.0743	7.7
Variables - Hour 20			
Constant (Hour 20)	1.0658	0.0067	158.0
Daylight20	-0.1137	0.0119	-9.6
Saturday	0.0441	0.0049	8.9
Sunday	0.0602	0.0049	12.3
Tdiff_20	0.0029	0.0010	2.9
AR coefficient	0.5895	0.0881	6.7

Equation: LNORM_18 = C(11) + C(12)* DAYLIGHT19+ C(13) * SATURDAY + C(14) *SUNDAY + C(15) * TDIFF_18 + [AR(1) = C(16)]
Observations: 60

R-squared	0.6442	Mean dependent var	1.0229
Adjusted R-squared	0.6112	S.D. dependent var	0.0307
S.E. of regression	0.0191	Sum squared resid	0.0198
Durbin-Watson stat	1.8243	0	
0			

Equation: LNORM_19 = C(21) + C(22)* DAYLIGHT19+ C(23) * SATURDAY + C(24) *SUNDAY + C(25) * TDIFF_19 + [AR(1) = C(26)]
Observations: 60

R-squared	0.9204	Mean dependent var	1.0318
Adjusted R-squared	0.9130	S.D. dependent var	0.0579
S.E. of regression	0.0171	Sum squared resid	0.0158
Durbin-Watson stat	1.9348		

Equation: LNORM_20 = C(31) + C(32)* DAYLIGHT20 + C(33) * SATURDAY + C(34) * SUNDAY + C(35) * TDIFF_20 + [AR(1) = C(36)]
Observations: 60

R-squared	0.9043	Mean dependent var	1.0399
Adjusted R-squared	0.8955	S.D. dependent var	0.0472
S.E. of regression	0.0153	Sum squared resid	0.0126

[23]A t-statistic is a conventional measure of the statistical significance of an estimated model parameter. As Table 3.3 indicates, it is computed as the ratio of the estimated coefficient to its standard error. Typically, a t-statistic greater than 2 indicates a 95 percent probability that the coefficient is, in fact, not equal to zero. Thus, a t-statistic of 9 reflects a coefficient that is estimated with very high precision.

These coefficients can be interpreted as the expected change in the (normalized) load from going from darkness to daylight over that entire hour. Thus, during the hour from 6 p.m. to 7 p.m., the model suggests an approximate 16 percent reduction in the total system energy demand. This is a very large change and suggests that behavioral factors related to lighting and appliance use have a large influence on the system demand, in addition to potential impact of daylight reducing the need for electric lighting. This topic will be discussed further in Section 3.3. The potential impacts of the daylight variables also vary across the hours modeled, with the largest potential impact in the 6 p.m. to 7 p.m. time frame, with a lesser potential impact in the subsequent hour. Again, these differences also suggest that behavioral factors play a large role in how daylight potentially impacts electricity use.

The Saturday and Sunday variables are essentially used as conditioning variables; in the normalized load specification, the interpretation of the coefficients on these variables is not straightforward. Clearly, the statistical significance of the coefficients for the Saturday and Sunday variables suggests a systematic difference in the pattern of demand for these weekend days. The negative potential impacts for the 6 p.m. (hour 18) regression are consistent with more leisure activities outside the home (with lower electricity use) in the late afternoon. In the subsequent hours, electricity use is relatively higher than the corresponding periods during the weekdays.

The coefficients on the temperature-difference variables are all statistically significant, particularly for the equations related to the first two hours. The positive signs on all of the coefficients suggest that a higher temperature increases the demand for that hour, indicating that temperature changes over the estimation period have a dominant potential impact on electricity used for cooling.

With the estimated coefficients for the daylight variables (Daylight18, Daylight19, and Daylight 20, in this case) in hand, the procedure for estimating the electricity consumption potential impact under the EPAct 2005 EDST calendar is straightforward. The daylight variables are computed for each hour for which an EDST potential impact is presumed to occur. The variables are computed under both the current law (calendar) and under the revised dates for EDST under EPAct 2005.

An illustration of differences in the daylight variable for the hours ending at 7 p.m. and 8 p.m. for Los Angeles are shown in Figure 3.9 and Figure 3.10. For example, the line denoted by the (pink) squares in Figure 3.9 shows that the fraction of daylight during the 6 p.m. to 7 p.m. hour increases from 5 percent to 45 percent from March 1 through April 3; and then increases to 100 percent of the hour when DST goes into effect. Had EPAct 2005 been in effect, DST in 2004 would have started on March 14 rather than April 4. Thus, on March 14, the fraction of daylight during this hour would jump from just more than 20 percent to 100 percent. In the subsequent hour (shown in Figure 3.10), the percentage of daylight would change on March 14 from zero (darkness) to just more than 20 percent (i.e. reflecting a shift in clock by exactly one hour).

Using the values for the daylight fractions, Table 3.4 shows the predicted normalized loads—without EDST and with EDST—for the 21 days between March 14 and April 3. The percentage changes in the predicted demands are highlighted. The predicted demands are computed in a straightforward fashion, aligning with the specification in Equation (3.5).

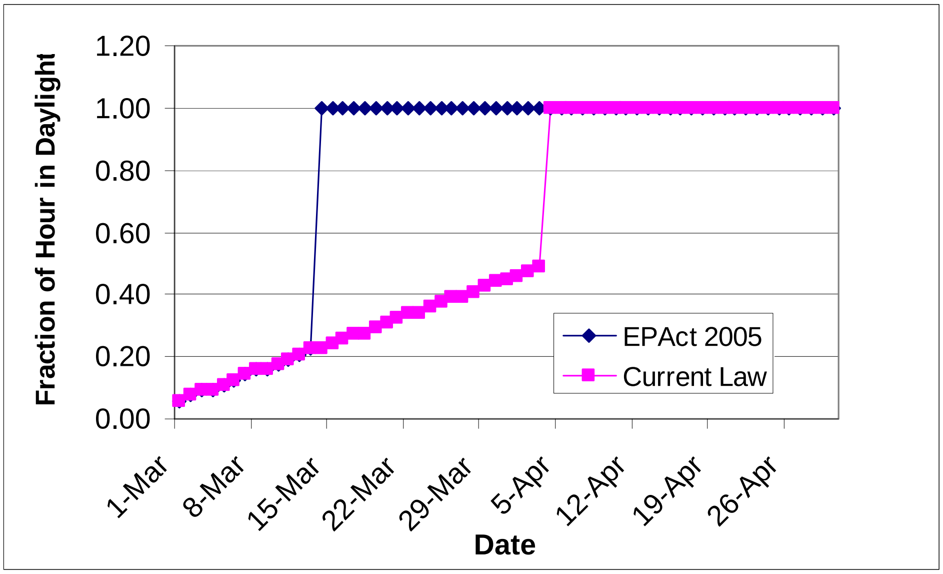
For example, the predicted normalized load for the hour ending at 7 p.m. is calculated as

Predicted Normalized Load = 1.1235 - 0.1603 * Daylight19

For this calculation, Saturdays, Sundays, and the temperature differences are ignored. The effects from these variables are sufficiently small having only a negligible effect on the estimated *percentage* change in the demand.[24]

At the bottom of the table are shown the average daily percentage differences in the energy demand for each affected hour over the 21-day period in which DST would have been in effect under EPAct during 2004. These average percentage changes are applied to the total regional demands to develop the aggregate potential impacts of EDST. This process is explained in detail in Section 4 of the report.

Figure 3.9. Computed Fraction of Daylight in Hour 6 P.M. to 7 P.M. for March and April in Los Angeles



[24] As stated, the omission of these variables makes only a very small difference in the average *percentage* change in the demands over the periods affected by EDST. Appendix A discusses some additional analysis in which all the variables were employed at their observed values, with the exception of the daylight variables with and without EDST, to predict the demands. For Los Angeles, the use of all of the variables to predict the average percentage changes over the 21-day period in the spring yielded reductions of 2.68 percent, 9.61 percent, and 3.84 percent in the demand for the hours ending from 7 p.m. through 9 p.m.. With the use of daylight variables only (as shown at the bottom of Table 3.5 to two significant digits), the corresponding percentage changes are 2.66 percent, 9.62 percent, and 3.84 percent. The relative closeness of these results was also observed for other locations. The application of coefficients for only the daylight variables helped to simplify the process of translating the model coefficients estimated by EViews and generating the predicted demands in individual spreadsheets used for that purpose.

Figure 3.10. Computed Fraction of Daylight in Hour 7 P.M. to 8 P.M. for March and April in Los Angeles

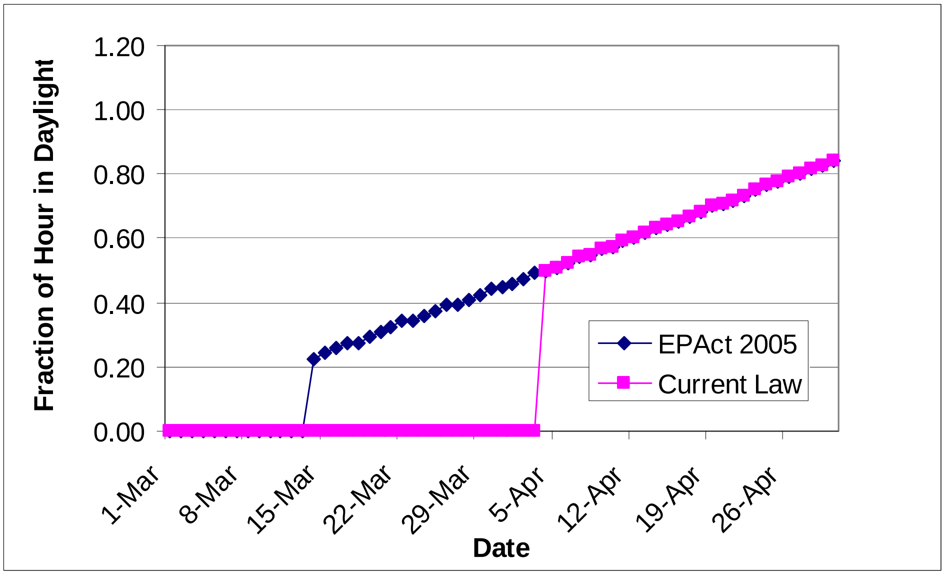


Table 3.4. Predicted Normalized Loads under Current Law and EPAct 2005 for Spring in Los Angeles

	Hour: 5 PM to 6 PM			Hour: 6 PM to 7 PM			Hour: 7 PM to 8 PM		
				Variable	Est. Coef.		Variable	Est. Coef.	
	Constant	1.0478		Constant	1.1235		Constant	1.0658	
	Daylight19	-0.0429		Daylight19	-0.1603		Daylight20	-0.1137	
Date	Current Law	EPAct 2005	% Chg.	Current Law	EPAct 2005	% Chg.	Current Law	EPAct 2005	% Chg.
14-Mar	1.038	1.005	-3.2%	1.087	0.963	-11.4%	1.066	1.040	-2.4%
15-Mar	1.037	1.005	-3.1%	1.085	0.963	-11.2%	1.066	1.038	-2.6%
16-Mar	1.037	1.005	-3.1%	1.082	0.963	-11.0%	1.066	1.036	-2.8%
17-Mar	1.036	1.005	-3.0%	1.079	0.963	-10.8%	1.066	1.034	-2.9%
18-Mar	1.036	1.005	-3.0%	1.079	0.963	-10.8%	1.066	1.034	-2.9%
19-Mar	1.035	1.005	-2.9%	1.077	0.963	-10.5%	1.066	1.033	-3.1%
20-Mar	1.035	1.005	-2.9%	1.074	0.963	-10.3%	1.066	1.031	-3.3%
21-Mar	1.034	1.005	-2.8%	1.071	0.963	-10.1%	1.066	1.029	-3.5%
22-Mar	1.033	1.005	-2.7%	1.069	0.963	-9.9%	1.066	1.027	-3.6%
23-Mar	1.033	1.005	-2.7%	1.069	0.963	-9.9%	1.066	1.027	-3.6%
24-Mar	1.032	1.005	-2.7%	1.066	0.963	-9.6%	1.066	1.025	-3.8%
25-Mar	1.032	1.005	-2.6%	1.063	0.963	-9.4%	1.066	1.023	-4.0%
26-Mar	1.031	1.005	-2.5%	1.061	0.963	-9.2%	1.066	1.021	-4.2%
27-Mar	1.031	1.005	-2.5%	1.061	0.963	-9.2%	1.066	1.021	-4.2%
28-Mar	1.030	1.005	-2.5%	1.058	0.963	-9.0%	1.066	1.019	-4.4%
29-Mar	1.030	1.005	-2.4%	1.055	0.963	-8.7%	1.066	1.017	-4.5%
30-Mar	1.029	1.005	-2.3%	1.053	0.963	-8.5%	1.066	1.016	-4.7%
31-Mar	1.028	1.005	-2.3%	1.051	0.963	-8.4%	1.066	1.015	-4.8%
1-Apr	1.028	1.005	-2.3%	1.050	0.963	-8.3%	1.066	1.014	-4.9%
2-Apr	1.027	1.005	-2.2%	1.047	0.963	-8.0%	1.066	1.012	-5.1%
3-Apr	1.027	1.005	-2.1%	1.045	0.963	-7.8%	1.066	1.010	-5.2%
Average ------->			-2.7%			-9.6%			-3.8%

Changes in Loads during the Morning Hours

While the 24-hour plots of average hourly demands for the selected weeks before and after the DST transition (Figure 3.5) appear to show little change in the demand in the morning, is that observation corroborated by the use of normalized loads? Figure 3.11 shows the normalized loads for three morning hours. In Figure 3.12, the percentage of daylight is plotted for the two hours where the fraction of daylight changes after the DST transition (on April 4, Day No. 35).

Figure 3.11. Normalized Loads for Morning Hours in March-April 2004 in Los Angeles

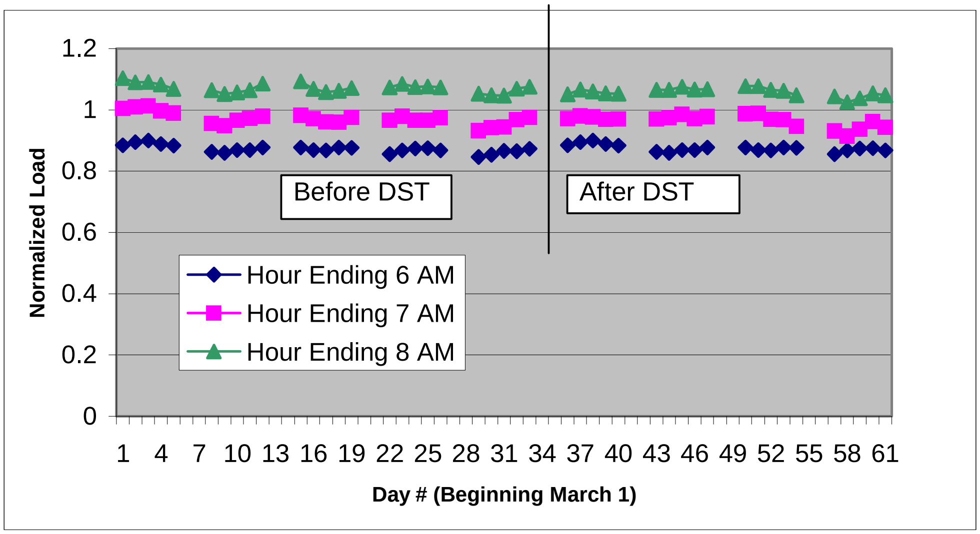
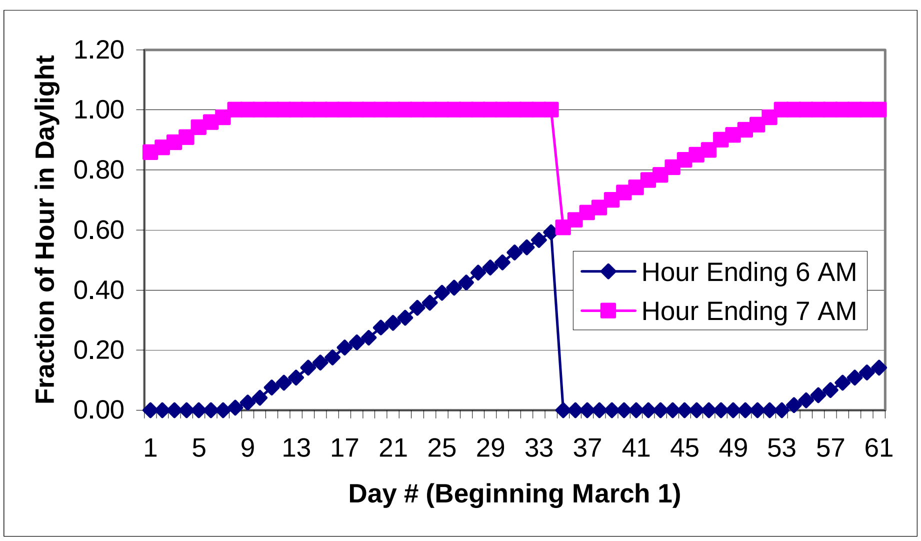


Figure 3.12. Percentage of Daylight in Hours Ending at 6 A.M. and 7 A.M. in March-April in Los Angeles



In the week after the DST transition, the normalized load in the 6 a.m. hour does increase, but that change is not sustained in the succeeding week. Thus, it is difficult to associate this increase with the reduction in daylight based on casual observation. Inspection of the demand for the 7 p.m. hour would also suggest no correlation with the daylight variables for that hour.

In general, it is likely to be more difficult to find a statistical correlation between the daylight variables and the morning demands than in the evening. Sunrise is naturally occurring earlier over the course of the spring and, thus, daylight during these hours steadily increases both before and after the DST transition. This fact indicates that any daylight effects will show up most strongly in the weeks just before and after the transition. In any particular data period, weather and other factors may obscure the potential impact of reduced demand in these weeks. In essence, there are fewer effective observations in the morning, as compared to the evening, to provide a robust estimate of the potential impacts of less daylight.

Although these plots do not reveal a systematic response to daylight as do those for the evening, a statistical analysis of this period suggests that electricity use may indeed increase slightly during this period. The regression results of applying the normalized load model are shown in Table 3.5.

The coefficients for Daylight6 and Daylight7 indicate that demands are slightly higher with less daylight during these hours. It appears reasonable that the coefficient on Daylight7 is higher than Daylight6, as more people are likely to be waking up during this hour and using electric lights.

The coefficients on the dummy variables again are primarily used to condition the overall model. The coefficients all have high statistical significant as one would expect the pattern of (relatively early) morning demands to be very different on weekends as compared to weekdays.

The actual coefficients on the daylight variables cannot be taken directly as a measure of the demand change—they must be multiplied by the values of daylight variables to show the change in the energy demand. From Figure 3.12, one sees that the transition to DST results in a change of only 0.4 in the daylight variable for the hour ending at 7 a.m., on either side of the transition (i.e., daylight is present for the entire hour before DST to daylight present for only 0.6 of the hour after DST). The model implies that the *predicted* increase in the demand from the model is less than 2 percent (0.4 * 0.049), and that even that change diminishes quickly as the sun rises earlier and earlier over the course of April. When applied to change in the DST calendar from EPAct 2005, the overall increase during the 7 a.m. hour is predicted to be a little more than 3 percent.

As the magnitudes of these changes are very small, one necessarily must be circumspect about their specific values. Logically, there has to be some increase in the demand during these hours, as street and other outdoor lighting must be used longer during the morning. There is likely to be some small increase in electric lighting in homes during these hours as well, but it could be presumed that the use of daylit rooms in the morning would be much lower than that in evening. Because these magnitudes are very small and may be masked by many other factors influencing the demand during this part of day, the statistical significance of the daylight variables will likely be much lower as compared to the application of the model to the evening hours. That supposition is borne out by the relatively low level of significance of these variables in the model for Los Angeles, but they still appear to meet minimal criteria for statistical significance.

Table 3.5. Regression Results for Normalized Load Model for Morning Hours, Spring 2004, Los Angeles

System: SYS67ARSUR
Estimation Method: Seemingly Unrelated Regression
Date: 02/16/06 Time: 07:54
Sample: 6 56
Included observations: 52
Total system (balanced) observations 102
Iterate coefficients after one-step weighting matrix
Convergence achieved after: 1 weight matrix, 17 total coef iterations

	Coefficient	Std. Error	t-Statistic	Prob.
Variables - Hour 6				
Constant	0.8822	0.0030	297.7	
Daylight6	-0.0240	0.0087	-2.8	
Saturday	0.0277	0.0038	7.3	
Sunday	0.0630	0.0038	16.6	
Tdiff_6	0.0027	0.0008	3.3	
AR coefficient	0.2182	0.1395	1.6	
Variables - Hour 7				
Constant	1.0193	0.0160	63.5	
Daylight7	-0.0486	0.0174	-2.8	
Saturday	-0.0490	0.0038	-13.0	
Sunday	-0.0326	0.0039	-8.4	
Tdiff_7	0.0034	0.0010	3.4	
AR coefficient	0.3663	0.1232	3.0	

Equation: LNORM_6 = C(21) + C(22)* DAYLIGHT6 + C(23) * SATURDAY + C(24) *SUNDAY +C(25) * TDIFF_6 + [AR(1) = C(26)]
Observations: 51

R-squared	0.8622	Mean dependent var	0.8867
Adjusted R-squared	0.8469	S.D. dependent var	0.0263
S.E. of regression	0.0103	Sum squared resid	0.0048
Durbin-Watson stat	2.0616		

Equation: LNORM_7 = C(31) + C(32)* DAYLIGHT7 + C(33) * SATURDAY + C(34) * SUNDAY +C(35) * TDIFF_7 + [AR(1) = C(36)]
Observations: 51

R-squared	0.8382	Mean dependent var	0.9549
Adjusted R-squared	0.8202	S.D. dependent var	0.0248
S.E. of regression	0.0105	Sum squared resid	0.0050

3.3 Summary of Electricity Use Results

3.3.1 Estimated Impacts by Location

Table 3.6 through Table 3.8 present the predicted changes in the electricity demand that would result from an earlier start of DST in the spring. The predicted changes are based on a (counterfactual) historical 2004 scenario in which DST would have begun on March 14 rather than April 4.

Table 3.6 presents the predicted changes for the four hours of the evening that were considered in the various statistical models. For the first four locations chosen in the East and Midwest, the results are congruent with their relative positions in the time zones and hours in which the amount of daylight changes. In the locations on the eastern portions of the time zones (Boston and Chicago), the savings show up primarily in the 6 to 7 p.m. time frame. Those savings are delayed to the following hour in the western locations (Detroit and Dayton).

Table 3.6. Predicted Percentage Change in Evening Demands: Spring DST under EPAct 2005

	End of Daylight	Hour of the Evening			
Location	on March 15[1]	5 PM to 6 PM	6 PM to 7 PM	7 PM to 8 PM	8 PM to 9 PM
Boston (NE Mass)	6:05 PM EST	- 3.4%	- 7.0%	- 1.6%	
New York	6:16 PM EST	- 1.7%	- 5.0%	- 2.5%	
Detroit	6:54 PM EST		- 4.3%	- 9.0%	- 0.7%
Dayton	6:58 PM EST		- 3.3%	- 8.0%	- 0.8%
Chicago	6:11 PM CST	- 4.2%	- 8.5%	- 1.8%	
Indianapolis	7:06 PM EST			- 4.0%	- 1.4%
Texas Municipal	6:52 PM CST		- 0.4%	- 5.0%	- 0.1%
Atlanta	6:58 PM EST		- 0.1%	- 6.4%	- 0.4%
Miami	6:41 PM EST		- 2.1%	- 6.0%	- 0.8%
Denver	6:20 PM MST	- 1.7%	- 6.5%	- 3.3%	
Portland, OR	6:34 PM PST	- 0.9%	- 2.9%	- 5.8%	
Los Angeles	6:14 PM PST	- 2.7%	- 9.6%	- 3.8%	

[1] End of daylight adds one-half of length of civil twilight to sunset time.

Until this year (2006), the portion of Indiana including Indianapolis has not observed DST. Simply based on the coefficients of the statistical model, the predicted percentage change in the energy demand in response to DST during these three weeks in March is about one-half of the other northern cities. Some further discussion of this difference is provided below.

The predicted savings in three locations in the southern portion of the United States are considerably lower than in the North, although there is considerable variation across these locations. The one-hour equivalent reductions are the smallest in the Texas utility at 5.5 percent, but are predicted to be higher in Miami (nearly 9 percent).

The two locations on the West Coast also display a large difference. Estimated savings in Portland are about 10 percent, reasonably close to those in the other northern locations in the Midwest and East. The savings in Los Angeles are the highest of any location analyzed, with savings of nearly 16 percent (again, as measured as the potential impact in a single hour).

Table 3.7 presents the predicted percentage *increases* in the morning's electrical consumption that would result from later sunrises in terms of clock time. As discussed earlier, with respect to Los Angeles, the statistical precision of these estimates is considerably lower than that for the evening estimates. First, the influence of daylight in homes during the morning is expected to be much lower than that in the evening. Second, the normally increasing amount of daylight is, in essence, interrupted by the DST potential impact, which reduces the information content of the data set. Because the hourly demand data reflect the effects of temperature and other weather factors (not accounted for in the model), as well as random shocks from other nonweather factors, it should be no surprise that discerning this very small (1 or 2 percentage point) potential impact is difficult.

Table 3.7. Predicted Percentage Change in Morning Demands: Spring DST under EPAct 2005

	Beginning of Daylight	Hour of the Morning			Statistical Confidence: Daylight Variable(s)
Location	on March 15[1]	5 AM to 6 AM	6 AM to 7 AM	7 AM to 8 AM	T-Statistics
Boston (NE Mass)	5:41 AM EST	1.2%	0.9%		(1.3, 1.0)
New York	5:52 AM EST	0.6%	0.5%		(0.6,1.4)
Detroit	6:29 AM EST		1.6%	0.5%	(2.5)
Dayton	6:33 AM EST		0.9%	0.5%	(1.3)
Chicago	5:41 AM CST	1.0%	1.1%		(1.7,2.8)
Indianapolis	6:42 AM EST		2.0%	1.8%	(3.9)
Texas Municipal	6:28 AM CST		2.1%	0.8%	(1.7)
Atlanta	6:34 AM EST		1.1%	0.7%	(1.3)
Miami	6:18 AM EST		1.8%	0.3%	(0.8)
Denver	5:56 AM MST		3.3%		(6.1)
Portland, OR	6:08 AM PST		3.1%		(1.1)
Los Angeles	5:50 AM PST	1.0%	3.2%		(2.8,2.8)

[1] Beginning of daylight defined as one-half of civil twilight prior to sunrise.

To help put these estimates into context, the t-statistics of the daylight variables used in the normalized load regressions are shown in the last column of the table. While many of these values are low (< 1.5), the estimated coefficients across all of the data sets were of the expected negative sign. In three locations that observed DST in 2004—Los Angeles, Detroit, and Denver—the statistical confidence is reasonably good with t-statistics greater than 2.5

Table 3.8 presents estimates of the average *daily* change in the demand, based on combining the predicted morning and evening percentage changes. The morning demand, on average, is lower than the average hourly demand for the day, and *vice versa*, for the evening peak hours. The percentage changes have been weighted to account for this difference.

The results indicate average daily savings of total electrical energy between 0.5 percent and 0.6 percent in the North, and between about 0.2 percent and 0.4 percent in the South.[25] These savings

[25] When these results are combined, Los Angeles is no longer the modest outlier, as in the preceding tables. The predicted percentage change is about 0.6 percent per day as for the northern cities.

would apply to each day affected by the EDST provision.[26] The next section in the report assigns a set of regional weighting factors to these estimates to develop an estimate of the national energy savings.

Table 3.8. Predicted Percentage Change in Daily Electricity Use: Spring DST under EPAct 2005

Location	Morning	Evening	Net Chg.
Boston (NE Mass)	0.08%	- 0.58%	- 0.5%
New York	0.04%	- 0.44%	- 0.4%
Detroit	0.09%	- 0.64%	- 0.6%
Dayton	0.06%	- 0.55%	- 0.5%
Chicago	0.08%	- 0.67%	- 0.6%
Indianapolis	0.13%	- 0.26%	- 0.1%
Texas Municipal	0.10%	- 0.26%	- 0.2%
Atlanta	0.08%	- 0.32%	- 0.2%
Miami	0.07%	- 0.45%	- 0.4%
Denver	0.13%	- 0.55%	- 0.4%
Portland, OR	0.17%	- 0.45%	- 0.3%
Los Angeles	0.14%	- 0.76%	- 0.6%

Tables 3.9 through Table 3.11 are in the same format, with the estimated changes in electricity use from an extended DST in the fall.[27] A comparison of Table 3.6 and Table 3.9 shows that the estimated savings during the evening hours are generally slightly lower in the fall as compared to the spring. Taking a simple average—for locations where models were estimated in both periods—yielded a difference of about 10 percent.

One cannot determine any statistically meaningful differences between spring and fall in the increased use of *morning* electricity from DST. For Boston and the Texas utility, a statistically significant coefficient with the expected sign for the daylight variable could not be estimated. Some increase in these demands can be expected, and so values were imputed—roughly based on coefficients for utilities in the same region. With the exception of Atlanta, the predicted increases from the regression models ranged 2 percent to 4 percent.

Table 3.11 is constructed in the same way as Table 3.8, combining the morning and evening changes into a daily average change. Given the lower savings estimates, primarily in the evening hours, the overall change in daily savings is roughly a percentage point lower in the fall than in the spring.

[26] Depending on the calendar for a particular year, the spring savings would be for either three weeks or for four weeks, as the DST is slated to start on the second Sunday in March. Over a period of years, the three-week acceleration of DST would occur about 57 percent of the time. In the fall, the savings would always be for one week.
[27] Fall 2004 data were not available for Chicago; regression models were not estimated for Indianapolis.

Table 3.9. Predicted Percentage Change in Evening Demands: Fall DST under EPAct 2005

	End of Daylight	Hour of the Evening			
Location	on Nov. 1[1]	4 PM to 5 PM	5 PM to 6 PM	6 PM to 7 PM	7 PM to 8 PM
Boston (NE Mass)	4:51 PM EST	- 2.0%	- 9.4%	0.0%	
New York	5:05 PM EST		- 10.0%	- 0.4%	
Detroit	5:40 PM EST		- 4.6%	- 4.9%	- 1.3%
Dayton	5:48 PM EST		- 3.1%	- 6.6%	- 1.6%
Chicago	5:40 PM CST				
Indianapolis	5:56 PM EST				
Texas Municipal	5:54 PM EST	1.8%	0.5%	- 4.4%	- 2.1%
Atlanta	5:57 PM EST	0.9%	0.1%	- 4.9%	- 1.9%
Miami	5:51 PM EST	1.3%	0.1%	- 5.1%	- 1.5%
Denver	5:11 PM MST		- 8.5%	- 1.7%	
Portland, OR	5:13 PM PST		- 6.6%	- 1.3%	- 0.1%
Los Angeles	5:13 PM PST		- 8.4%	- 2.4%	- 1.0%

[1] End of daylight adds one-half of length of civil twilight to sunset time.

Table 3.10. Predicted Percentage Change in Morning Demands: Fall DST under EPAct 2005

	Beginning of Daylight	Hour of the Morning	
Location	on Nov. 1[1]	6 AM to 7 AM	7 AM to 8 AM
Boston (NE Mass)	6:03 AM EST		1.0%[2]
New York	6:12 AM EST		0.3%
Detroit	6:51 AM EST	0.2%	1.7%
Dayton	6:53 AM EST	0.2%	1.8%
Chicago	5:41 AM CST		
Indianapolis	6:42 AM EST		
Texas Municipal	6:33 AM CST		2.0%[2]
Atlanta	6:44 AM EST	0.2%	0.7%
Miami	6:18 AM EST	2.3%	0.5%
Denver	6:15 AM MST	0.6%	1.6%
Portland, OR	6:37 AM EST		1.0%
Los Angeles	6:01 AM PST	2.9%	

[1] Beginning of daylight defined as one-half of civil twilight prior to sunrise.
[2] No reasonable estimates obtained for this location -- imputed value.

Table 3.11. Predicted Percentage Change in Daily Electricity Use: Fall DST under EPAct 2005

Location	Morning	Evening	Net Change
Boston (NE Mass)	0.05%	- 0.59%	- 0.5%
New York	0.01%	- 0.51%	- 0.5%
Detroit	0.08%	- 0.51%	- 0.4%
Dayton	0.09%	- 0.53%	- 0.4%
Texas Municipal	0.08%	- 0.19%	- 0.1%
Atlanta	0.04%	- 0.27%	- 0.2%
Miami	0.09%	- 0.26%	- 0.2%
Denver	0.09%	- 0.50%	- 0.4%
Portland, OR	0.05%	- 0.39%	- 0.3%
Los Angeles	0.11%	- 0.59%	- 0.5%

3.3.2 Interpretation and Qualifications

This section provides some interpretation of the empirical results, as well as suggesting some qualifications. Three topics are discussed: 1) regional differences, 2) comparison with Indiana results, and 3) comparison with previous studies.

Regional Differences

While the small set of locations chosen in this assessment precludes any definitive conclusion about regional differences, they nevertheless point to somewhat lower savings in the South as compared to the North. The discussion above, concerning the effect of temperature, argued that the methods used here should adequately adjust for temperature differences, pre- and post-DST for a particular location.

The lower savings for the Southeast locations suggests that other factors may be behind these climate-dependent results. While temperature is clearly a determinant of cooling load, it is by no means the only one. The solar heat gain through windows (and, to a smaller degree, roof and walls) is a major source for the cooling loads in both commercial and residential buildings. According to estimates prepared by Lawrence Berkeley National Laboratory (LBNL 1998), the contribution from solar gain through windows to the total cooling load in residential building is nearly as great as that due to differences between indoor and outdoor temperatures (i.e., about 80 percent of the conduction gain from temperature differences). That estimate pertains to an entire year; in the spring and fall periods, in which this study focuses, the relative contributions from solar gain would be higher.

Thus, one interpretation of these results is that changes in solar gain may have significant potential impact on the realized savings from DST in the evening hours.[28] The empirical results for the fall in the three southern locations are consistent with this view. The statistical models show increased electricity use during the late afternoon hours (4 p.m. to 6 p.m. clock time) under DST, as compared to Standard Time. Because these solar gains affect cooling loads with some lag, they also offset, to some degree, the savings from additional daylight in the later evening hours.

While the discussion suggests solar gain may be the principal factor behind the lower estimated savings in the South, other complex interactions between temperature (and its lagged effects), humidity, and thermostat settings by residential customers also contribute to the electricity used for cooling during any particular hour. Building simulations are perhaps the best methods for investigating these factors.

Comparison with Indiana Results

The statistical model estimated for Indianapolis using data for March-April 2004, yields lower than predicted electricity savings in the evening hours, as compared to surrounding locations in

[28] In the context of the statistical model, the solar gain is an (unmeasured) omitted variable.

the region.[29] The estimated coefficients for daylight are roughly half of those estimated for the other northern locations where DST is observed.

This finding suggests that an alternative interpretation may be posited for the observed behavior of electricity use over DST transitions. The relatively high values of the daylight coefficients may result from essentially two factors: 1) normal response of outdoor lighting and occupant behavior, regarding substitution of electric lighting for daylighting, and 2) increased outdoor activity, *signaled* by DST, which further reduces the use of lighting and appliances. In this model, a DST transition provides a clear signal that "spring has arrived" or that "winter is approaching" that prompts a step function in household behavior.

Some empirical investigation of that hypothesis was carried out for several utility data sets—Los Angeles and Detroit. This postulated step function in behavior is represented by a simple dummy variable for DST that is added to model the specification in Equation (3.5). Ignoring the temperature and day type variables, we have:

$$\text{Lnorm}_{ht} = a_h + b * \text{Daylight}_{ht} + c_h * \text{DST}_t + \ldots\ldots\ldots + u \qquad (3.6)$$

In a statistical sense, the correlation between the daylight variable for a given hour and DST is very high during the two-month data set straddling the DST transition. This colinearity reduces the ability of the statistical model to robustly distinguish any separate effects that may underlie the available hourly demand data. To alleviate that problem, the daylight coefficients (b) in Equation (3.6) were restricted to be the same in all of the separate hourly demand equations that are estimated as a system.[30]

For Dayton, the estimated coefficient for the daylight variable was -0.052, indicating about a 5 percent reduction in the demand for a transition from total darkness to total daylight. That value compares very well with the estimated coefficient for Indianapolis of about -0.057. The Dayton model includes dummy variables for DST, with estimated coefficients in the hours ending 6 p.m. through 8 p.m. at -0.042, -0.048, and -0.14, respectively. In general, the statistical "fit" of this alternative model appears to be better than that using only the daylight variables.[31] Nevertheless, using this alternative model to *predict* the electricity savings from a March DST results in similar, although slightly greater, electricity savings as the standard model.[32]

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[29] As shown in Table 3.1, the data pertain to the Indianapolis Power and Light (IPL) utility. Even though this portion of Indiana does not observe DST, one can still estimate a response coefficient to an increase in daylight over the two-month period as used for the other locations.

[30] This model would hold exactly if all lighting were a deterministic function of the amount of daylight in each hour, as would be the case of outdoor lighting with sensors. Over a period of months, the change in the fraction of daylight during any hour would have the same potential impact on the demand, regardless of the clock hour in which it appeared.

[31] Moreover, in the model where the daylight coefficient is restricted to be equal in all evening hours, the t-statistics for both the daylight variable and the DST dummy variables exceed 2.

[32] This comparison of predicted savings was performed for Los Angeles and Dayton. The total predicted savings under this alternative model for Los Angeles were almost exactly the same, and the predicted savings for Dayton were about 15 percent greater. The model does indicate some greater differences in the specific hours in which the savings occur.

Unfortunately, this alternative model with its use of dummy variables, suggests a measure of the uncertainty with regard to how daylight actually influences household behavior during the evening hours at different times of the year.[33] The implication of the model is that the behavior of households outside of Indiana is somewhat different after the spring transition to DST—with people engaging in a slightly higher degree of outdoor activities (both as individual household behavior and activities such as organized youth sports). This interpretation of the data also suggests a somewhat more uncertain magnitude of predicted electricity savings that could be attributed to DST.[34]

Comparison with Previous Studies

While a full comparison with prior studies is beyond the scope of this assessment, a few observations may be useful. Beginning with the 1975 DOT Study, the results here suggest that the savings from an extension of DST may be half or less of that estimated by DOT. There are several reasons that suggest why the estimates from this study are lower.

First, as pointed out by the National Bureau of Standard review, DOT's use of the "Equivalent Day Normalization" method may still fail to adequately account for the shift in business and social schedules relative to the daily temperature profile caused by DST. As explained in Section 3.1, such an omission is likely to positively bias the estimates of DST savings in areas where electric space heating is important.[35] Moreover, the overall efficiency of electric space heating was lower in 1975 relative to today (i.e. greater response to temperature change), making that bias greater than it would be today. That bias may also be influenced by the particular choice of hours that are assumed to be influenced by DST.

The prevalence of air conditioning was also considerably lower than today. Thus, the estimates of savings for the southern locations are likely to be lower than those observed for 1975.

While these factors lead to lower estimated savings in the current study, they are likely insufficient to account for the entire difference. Application of the DOT methodology to the more recent data would help to explain the differences, but was outside the scope of this assessment.

[33] The lower values of the estimated savings from the November extension of DST, compared to March, are consistent with this model. Colder temperatures in late October in the North would clearly have a potential impact on outdoor activities, even with the same amount of daylight.

[34] A more rigorous statistical analysis may be able to shed further light on this issue. One approach would be to use a CEC-type model (with its greater attention to the construction of the weather variables) to analyze hourly demand data for the months of February through May. Regression models would be estimated over three time periods: 1) in February and March (including April days under Standard Time), 2) April and May under DST, and 3) for the complete four-month time period. One can employ standard statistical tests to determine whether the coefficients on the daylight variables remain stable over these various estimation periods. One could also use the February-March estimated parameters to predict April-May demands under the assumption of Standard Time and *vice versa*.

[35] In the parlance of the DOT approach, the outdoor temperatures are *systematically* higher in the "influenced periods" as compared to the "uninfluenced periods" during DST.

CEC Results

In general, the results obtained in this current study are reasonably consistent with those generated by CEC for California. One caveat, of course, is the results here apply only to Los Angeles and not to the remainder of California. As with the CEC study, the results from this study suggest lower savings from DST in the fall as compared to the spring.

One apparent difference between the CEC results and those estimated in the present study is the distribution of electricity savings (or changes) between the morning and evening. The estimated morning increase in electricity use is much higher (relative to evening savings) in this study as compared to the CEC method. On inspection of Figure 6.2 (Section 6.4), the CEC shows some increase in the morning use, but the magnitudes are very small.

There is no obvious explanation for this difference. The CEC study uses a much more complex model to try to disentangle the effects of temperature and daylight. However, the CEC method may blur some of the true potential impact of daylighting by aggregating over all of California (versus specific utility demand analysis as conducted in this study). Additionally, the CEC approach and the approach used in this study both suffer from the relatively large time intervals (one hour) when attempting to explain the pattern of electricity use in the morning. An approach using demand data with shorter time intervals (e.g., 15-minute data) could potentially improve these estimates.

While not directly related to *results*, it may be useful to comment on the 2001 review of the CEC approach by the Department of Energy's Energy Information Administration (EIA) at this point. EIA thought that the high geographic aggregation of the utility data across all of California "makes it difficult to accurately account for variation due to weather and daylight." CEC recognized this deficiency and acknowledged that they intended to try to estimate the model for specific utilities within the state. This aggregation problem was recognized in the early stages of the study, as an attempt was made to use the aggregate Texas utility energy demand for the Electricity Reliability Council of Texas (ERCOT). A satisfactory model could not be estimated with this data. Subsequently, the effort was made to secure hourly demand data for a specific municipal utility in Texas.

EIA also wrote:

> *EIA has concluded that the theoretical model underlying the CEC analysis is based on the assumption that the "residuals" (unobserved "shocks" that cause consumption to be higher or lower than normal) from day-to-day are independent.*

CEC also acknowledged this phenomenon, but found it difficult to correct for in the 24-hourly equation structure of their model. This autocorrelation of residuals (from one day to the next at the same hour) was also present in most of the data sets examined in this study. With models that included, at most, equations for four separate hours of the evening, the econometric software was able to readily incorporate an adjustment for this behavior. Typically, the key parameter estimates did not change significantly after this adjustment, although their standard errors were lower as is predicted by statistical theory.

Measures of Uncertainty

No comprehensive derivations of uncertainty ranges for the predicted savings were undertaken in this study.[36] For this assessment, the focus was on development of a satisfactory model structure that could provide point estimates of the expected savings in different locations in the United States. As discussed above, the empirical results appear to be generally consistent with those of CEC, and show some regional sensitivity as expected by an understanding of building thermal loads.

Appendix A develops a methodology to form uncertainty ranges (confidence intervals) for the daily percentage changes in the demand that may be expected under EDST. The methodology is based on the standard errors of the regression coefficients for the morning and evening models. The focus is on how the uncertainty in the estimated model coefficients, particularly for the daylight variables, translates into uncertainty that would pertain to the expected (or long-term average) changes in the demands under EDST.

The methodology was applied to four locations as shown in Table 3.12. The top row for each location shows the point estimate for the percentage change in the daily demand, repeating the values shown in Table 3.8. Beneath each value is the uncertainty range (or relative confidence limits) evaluated at a 90 percent level of confidence. Thus, for example in Dayton, the uncertainty range in the *daily* demand due to the EDST impact during the evening hours is estimated to be +/- 17 percent. The resulting confidence limits for the percentage reduction in the average daily demand due to the evening hours is 0.46 percent to 0.64 percent (e.g., (0.83 * 0.55 percent = 0.46 percent and 1.17 * 0.55 percent = 0.64 percent).

Table 3.12. Uncertainty Ranges (90 percent Confidence Level) for Predicted Percentage Changes in Systems Demands for Selected Locations – for Spring 2004 Demand Models

Location		Morning	Evening	Day
Detroit	% Change in demand due to:	0.09%	- 0.64%	- 0.56%
	Uncertainty range:	(+/- 80%)	(+/- 11%)	(+/- 17%)
Dayton	% Change in demand due to:	0.06%	- 0.55%	- 0.49%
	Uncertainty range:	(+/- 128%)	(+/- 17%)	(+/- 24%)
Atlanta	% Change in demand due to:	0.08%	- 0.32%	- 0.24%
	Uncertainty range:	(+/- 107%)	(+/- 29%)	(+/- 49%)
Los Angeles	% Change In demand due to:	0.14%	- 0.76%	- 0.63%
	Uncertainty range:	(+/- 52%)	(+/- 18%)	(+/- 26%)

As discussed previously, and implied by the low t-statistics for the daylight variables, the confidence intervals for the morning change in the demand are considerably larger than those for the evening hours. In several cases (Dayton and Atlanta), this range at the 90 percent level of confidence includes values between zero and double the estimated value. Further study, including perhaps information collected on a sub-hourly basis, is needed to better measure this potential impact from DST.

[36] While CEC did provide some uncertainty measures in their report, EIA had some issues with regard to how these measures were computed.

Depending on the relative magnitude and precision of the morning demand predictions, the confidence limits for the daily average savings will be affected. Clearly, the relative uncertainty for Atlanta is significantly higher than the other locations, with uncertainty ranges of +/- 49 percent of the point estimate. Because the estimated savings for all of the other locations in the South appear to be approximately the same (with generally imprecise coefficient estimates as to how daylight would affect the morning demands), it could be expected that these other locations may also have uncertainty ranges greater than 40 percent.

To conclude this discussion, even this limited application of the uncertainty methodology appears to provide some useful ranges from which one may set an overall confidence interval for the national-level estimates. With the exception of Detroit, uncertainty ranges for the other locations are between +/- 24 percent to +/- 49 percent. Accordingly, a reasonable, and perhaps conservative, estimate of the overall uncertainty range for nationwide electricity savings was determined to be +/- 40 percent. This range is used in the following section as a means of bounding the national estimates of electricity savings from the implementation of EDST.

3.3.3 Comparison of Specifications.

As discussed at the outset of Section 3.1, specifications using both the absolute levels of the demands, as well as those using "normalized loads," were both employed at different stages in the study.[37] For the reasons cited earlier, the normalized load specification became the preferred specification for a number of reasons, perhaps principally because it is easier to directly observe how the demand profile varies over the course of the data period.

Table 3.13 shows a comparison of the predicted savings from the separate approaches for six locations. In general, the predicted values are consistent with each other, leading to the conclusion that no substantive bias is incurred by the use of the normalized demands.

Table 3.13. Comparison of Predicted Savings under Alternative Model Specifications

Location	Absolute Demand Specification			Relative Demand Specification		
	5 PM to 6 PM	6 PM to 7 PM	7 PM to 8 PM	5 PM to 6 PM	6 PM to 7 PM	7 PM to 8 PM
Boston (NE Mass)	3.9%	7.3%	2.1%	3.5%	8.7%	2.8%
Chicago		7.7%	2.3%		8.4%	1.9%
Texas Municipal		0.0%	3.9%		0.3%	4.6%
Miami		2.0%	6.0%		2.2%	6.0%
Portland, OR		3.8%	6.1%		3.2%	6.3%
Los Angeles		10.6%	4.1%		8.0%	3.1%

3.3.4 Comparison Across Years

For several locations, the normalized model was estimated for 2002 and 2003, in addition to 2004. As shown in Table 3.14, the predicted savings based on the parameter estimates derived from those years are very similar to the predicted savings derived from the 2004 data. The largest

[37] The results for the "normalized load" specifications do not match those from Table 3.7, as they are based on models using only weekdays, and may differ in terms of estimation method and hours included in the system. Nevertheless, the results are very consistent with those obtained with the absolute demands specification.

differences pertain to Portland. While the distribution of potential impacts over the evening hours seems to be somewhat different in 2004, as compared to the two prior years, the overall potential impact over the three hours is approximately the same. The estimated total impacts for the Texas utility are somewhat lower in 2002 as compared to those for the subsequent two years. Overall, given these results, it is expected that the magnitude of the overall estimates of national electricity savings would be little affected by the use of data from these other recent years.

Table 3.14. Comparison of Predicted Change in Demand for Alternative Years

Location	Year	5 PM to 6 PM	6 PM to 7 PM	7 PM to 8 PM	8 PM to 9 PM
Los Angeles	2004	- 2.7%	- 9.6%	- 3.8%	
	2002	- 1.9%	- 9.2%	- 4.2%	
Texas Municipal	2004		- 0.4%	- 5.0%	- 0.1%
	2003		- 0.3%	- 4.9%	- 0.1%
	2002		+ 0.3%	- 4.4%	- 0.1%
Portland, OR	2004	- 0.9%	- 2.9%	- 5.8%	
	2003	- 1.8%	- 3.3%	- 4.6%	
	2002	- 1.8%	- 3.5%	- 4.8%	

4 National Energy Savings

The above analysis calculated percentage changes in electricity demand for the hourly profiles during the time of EDST for specific utilities. These changes can be incorporated into the hourly electricity demand schedules of each of these utilities to find the amount of savings and applied to all regions across the United States. Based on marginal cost information for representative utilities, an estimate of the type of fuel and efficiency of conversion can be made. This allows an estimate of the amount of total energy saved by extending DST.

4.1 NERC Reliability Regions

The Unites States, along with Canada and Mexico, are separated into electrical reliability regions, all guided by the North American Electric Reliability Council (NERC). Each year, the organization distributes information such as monthly Net Electric Load and Peak Demand in an Electricity Supply and Demand database (ES&D).[1] The regions, as of 2004, are shown in Figure 4.1. (There were a number of modifications to the regional boundaries in 2005, but this study is using 2004 data for its analysis.) This study will only evaluate the U.S. portion of the NERC regions. The Alaska Systems Coordinating Council is an associate member of NERC, but not considered in our analysis. Hawaii does not follow DST, so it is not analyzed in this study either.

Figure 4.1. NERC Regions [1]

Because the Western Electricity Coordinating Council (WECC) region covers a large territory of varying geography, climate, and economic activity, its subregions were used in this study. There are four subregions, as shown in Figure 4.2. While the largest in area is the Northwest Power Pool Area, the California/Mexico Power Area has the highest amount of sales. Because Arizona does not follow DST, the results for its subregion must be scaled down to reflect that the 53 percent of sales that are in Arizona will not be affected by DST.

Figure 4.2. WECC Regions: 1) Northwest Power Pool Area, 2) Rocky Mountain Power Area, 3) Arizona/ New Mexico/ Southern Nevada Power Area, 4) California/Mexico Power Area [2]

Table 4.1 lists the utilities assigned to each region. The utilities/cities analyzed for the potential impact of EDST are scattered throughout the country. However, some of the regions did not include a city that was analyzed. For this reason, it was necessary to assign utilities to each region based on their location. Either the city assigned was near the region, or it was located in a similar spot within the time zone of the region to be analyzed. For example, the Midwest Regional Organization (MRO) had no cities within it that were evaluated. Rather than use Chicago, which was closest, Detroit was used, because it is located more in the western part of its time zone, a better match to the time zone of the MRO region. Figure 5.2 in Part 3 of this report shows the location of key U.S. cities within their respective time zones.

Table 4.1. NERC Regions and Utilities Assigned to Each

NERC Region	Spring Utility for DST	Fall Utility for DST	Utility for System Lambda
ECAR	Detroit Edison + Dayton Power	Detroit Edison + Dayton Power	AEP (Spg) + Dayton (Fall)
ERCOT	Texas Municipal	Texas Municipal	AEP-SPP
FRCC	Florida P&L (Miami)	Florida P&L	Florida P&L
MAAC	Consolidated Edison of New York	Con Ed	PJM West
MAIN	Commonwealth Edison (Chicago)	ISO-NE (NEMass)	Commonwealth Edison
MRO	Detroit Edison	Detroit Edison	Minnesota P&L
NPCC	ISO-NE (NEMass)	ISO-NE (NEMass)	ISO-NE
SERC	Georgia Power (Atlanta)	Georgia Power	Southern Co.
SPP	Texas Municipal	Texas Municipal	AEP-SPP
WECC-AZN	Public Service of Colorado	Public Service of CO	Arizona Public Service
WECC-CNV	Los Angeles DWP	Los Angeles DWP	Los Angeles DWP
WECC-NWP	Portland GE	Portland GE	Seattle City Light
WECC-RMP	Public Service of Colorado	Public Service of CO	Arizona Public Service

Table 4.2. 2004 Net Energy for Load in NERC Regions (TWh) [1]

NERC Region	March-April	October-November	Annual
ECAR	87	85	553
ERCOT	41	45	289
FRCC	32	35	220
MAAC	44	42	284
MAIN	42	43	275
MRO	23	25	153
NPCC	45	46	293
SERC	124	132	857
SPP	28	29	192
WECC-AZN	18	18	123
WECC-CNV	43	45	279
WECC-NWP	35	37	223
WECC-RMP	9	9	57
Total	571	589	3,797

The monthly Net Energy for Load (NEL) (defined as system generation plus energy received from others, less energy delivered to others through interchange) for each region is listed in NERC's ES&D database.[1] Table 4.2 lists the amount of electrical demand for the two spring and two fall months, plus the annual total for each region. The electrical demands of the representative utilities analyzed above in each region were scaled to match the total demand for each region. Only the two spring and two fall months were used as scaling factors, to minimize distortions due to varying summer or winter energy demand.

Besides having representative utilities assigned to each region for DST savings, the regions also each had assigned to them a representative utility's hourly marginal cost, or system lambda. Each year, utilities report their hourly "system lambda" values to FERC on the same form as was used for reporting their hourly demands. The system lambda is the marginal cost of increasing generation by one MW over any given hour. The definition for system lambda on Form-714 is:

> *For control areas where load following is primarily performed by thermal generating units, the system lambda is derived from the economic dispatch function associated with automatic generation control performed at the controlling utility or pool control center. Excluding transmission losses, the fuel cost ($/hr) for a set of on-line and loaded thermal generating units (steam and gas turbines) is minimum [38] when each unit is loaded and operating at the same incremental fuel cost ($/MWh) [39] with the sum of the unit loadings (MW) equal to the system demand plus the net of interchange with other control areas. This single incremental cost of energy is the system lambda. System lambdas are likely recalculated many times in one clock hour. However, the indicated system lambda occurring on each clock hour would be sufficient for reporting purposes.*[3]

While not all utilities submit their system lambda data to FERC, there is a wider availability than those analyzed for DST savings. Some of the utilities that were used for calculating the DST potential impacts did not have their system lambdas posted on the FERC Web site. Future analysis could include additional cities that would cover more of the spectrum of NERC's regions. Table 4.1 lists the regions analyzed with the cities/utilities assigned for their DST savings or system lambda.

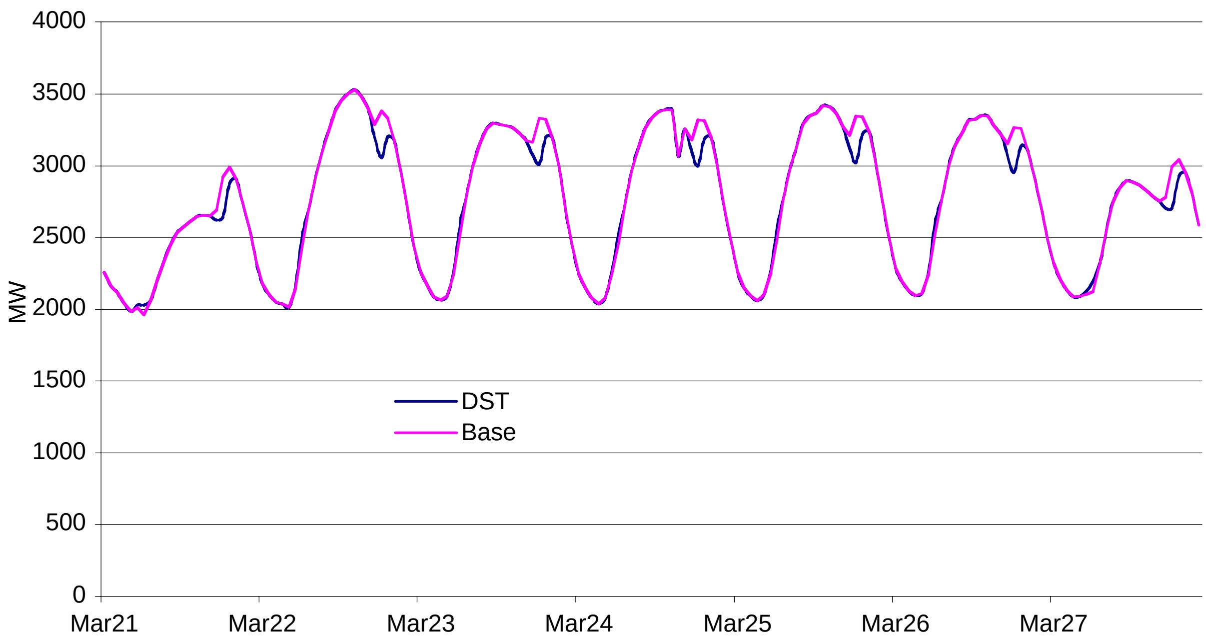
[38] Some utilities may also include variable operation and maintenance costs that they consider "dispatchable." Therefore, the costs to be minimized could include a variable O&M component as well as the fuel costs.
[39] Because unit heat rates and fuel costs vary, some units may not be able to operate at the same incremental fuel cost as the other units and, thus, those units may be loaded differently.

4.2 Electric Savings

The analysis in Section 3, calculated the average percentage reduction in demand for specific hours of each day of the DST extension. These percentages can be applied to the demand schedules of those days to determine the amount of electricity savings. Because of the statistical method used, a simplification was made that every day will have the same fractional reduction, rather than have it vary over the three-week time span or adjust for weekends. A more detailed analysis in a follow-on study may allow a differentiation over time or on weekends to be considered.

The hourly demand profiles of 2004 for each of the utilities examined were reduced during the EDST period. Figure 4.3 shows an example of one week's base demand and reduced demand for Los Angeles Department of Water and Power (LADWP). All three weeks from March 14 to April 3 will have this adjustment, as will the curves for the week of October 31 to November 6, based on its percentage changes. The resulting energy use and savings for each utility and period are shown in Table 4.3. Relative savings appeared lowest in the southern utilities and highest in the northern.

Figure 4.3. LADWP Hourly Demand 3/21/04 to 3/27/04 with and without EDST



The percentage savings in Table 4.3 applies to the period that DST is extended. The annual values range between 0.59 percent and 0.15 percent savings for each day. This can be compared to the 1 percent savings per day that was reported in the 1975 DOT study.[4] As can be seen, the values calculated here are somewhat less than in 1975. This may reflect the change in electrical uses and lowered amount that is sensitive to daylight changes.

Because the regional NEL is only available on a monthly basis, it is necessary to calculate the percent of electricity saved for each utility (or combination of utilities) over the same two-month periods as the regions they are assigned (Table 4.1). The regional NEL can then be multiplied by these percentages to determine the regional electricity savings for each region. These calculations are shown in Table 4.4. The result is 1,000 GWh of electricity saved from EDST. This equals 0.03 percent of total U.S. electricity use over the year.

Table 4.3. Utility Savings and Use during EDST periods 3/14/04-4/3/04 and 10/31/04-11/06/04

	SPRING EDST (3/14/04 – 4/3/04)			FALL EDST (10/31/04 – 11/6/04)			Annual
	Electricity Saved by DST (GWh)	Electricity Used (GWh)	Electricity Saved (%)	Electricity Saved by DST (GWh)	Electricity Used (GWh)	Electricity Saved (%)	Electricity Saved (%)
Portland GE	4	1,121	0.32%	1	408	0.34%	0.33%
ISO-NE (NEMass)	7	1,432	0.50%	2	449	0.48%	0.49%
Georgia Power	10	4,080	0.24%	4	1,479	0.24%	0.24%
Florida P&L	20	5,240	0.38%	4	2,120	0.17%	0.32%
Detroit Edison	18	3,154	0.56%	4	1,031	0.43%	0.53%
Dayton P&L	4	876	0.49%	1	280	0.42%	0.47%
Texas Municipal	1	529	0.16%	0	183	0.12%	0.15%
Los Angeles DWP	9	1,422	0.63%	2	474	0.47%	0.59%
Comwealth Edison	31	5,271	0.59%				0.59%
Consolid. Edison	13	3,122	0.40%	5	1,035	0.51%	0.43%
Public Serv of CO	9	2,085	0.42%	3	730	0.35%	0.40%

Table 4.4. Regional Net Electricity Savings from EDST

	SPRING (3/1/04 – 4/30/04)			FALL (10/1/04 – 11/30/04)			
NERC Region	Regional Energy (TWh)	Utility Savings over 2 months (%)	Regional Savings (GWh)	Regional Energy (TWh)	Utility Savings over 2 months (%)	Regional Savings (GWh)	Annual Savings (GWh)
ECAR	87	0.18%	160	85	0.05%	43	202
ERCOT	41	0.05%	22	45	0.01%	6	27
FRCC	32	0.13%	40	35	0.02%	7	47
MAAC	44	0.14%	61	42	0.06%	25	86
MAIN	42	0.20%	86	43	0.05%	23	109
MRO	23	0.19%	45	25	0.05%	12	57
NPCC	45	0.18%	81	46	0.05%	25	106
SERC	124	0.08%	102	132	0.03%	37	140
SPP	28	0.05%	15	29	0.01%	4	18
WECC-AZN	18	0.07%	12	18	0.02%	4	16
WECC-CNV	43	0.21%	93	45	0.05%	24	116
WECC-NWP	35	0.11%	38	37	0.04%	15	53
WECC-RMP	9	0.14%	13	9	0.04%	4	17
Total	571		768	589		228	996

The error bound for the amount of electricity change is roughly ± 40 percent, according to the analysis described in Appendix A. This translates into electricity savings of 600 GWh to 1,400 GWh annually for the entire country.

4.3 Conversion to Total Energy

As described above, the system lambda is the marginal cost of production at any given hour of operation. Applying the system lambda schedules from the utilities in Table 4.1 to the corresponding energy savings for each region provides an approximation of the costs that would be saved by the utilities in each region in 2004. The hourly costs ranged from $8/MWh to $155/MWh, depending on the region, date, and time of the energy savings.

A more difficult calculation is to determine the amount of total energy saved that would have generated the electricity saved by EDST. At any point in time, utilities will have one or more power plants available to raise or lower production to meet demands. As described in the definition of system lambda (Section 4.1), these plants will be dispatched based on the marginal cost to produce additional power. The consequent cost is a function of the cost of the fuel, the efficiency of the plant, and any other variable operations and maintenance (O&M) costs.

$$\text{Cost (\$/MWh)} = \text{Fuel Price (\$/mmBtu)} * \text{Heat Rate (Btu/kWh)} / 1000 + \text{Variable O\&M (\$/MWh)} \qquad (4.1)$$

Or:

$$\text{Heat Rate (Btu/kWh)} = (\text{Cost} - \text{Variable O\&M}) / \text{Fuel Price} \qquad (4.2)$$

The heat rate is a common term used to depict the efficiency of a power plant. Because one kWh equals 3,412 Btu, the equation to find the efficiency in percentage of "energy out" to "energy in" is:

$$\text{Efficiency (percent)} = 3412 \text{ (Btu/kWh)} / \text{Heat Rate (Btu/kWh)} * 100 \text{ percent} \qquad (4.3)$$

Any power plant may have different fuel prices and variable O&M costs. However, fuel prices will tend toward the average and, for lack of more specific information, the national average prices were found for each month from EIA's *Electric Power Monthly* data sets.[5] There are three main fuel types that will be used by plants that are likely on the margin at this time: coal, natural gas, and petroleum fuels. Each fuel actually has multiple subcategories, such as distillate versus residual oil, or different qualities of coal; and fuel prices can vary across the country—but the cost data were not readily available to provide further disaggregation. Furthermore, regional average fuel prices would still have the problem that they would not necessarily represent the actual fuel price of the facilities on the margin. The average fuel prices to electric utilities for each month of interest in 2004 are shown in Table 4.5. Note that oil and gas prices increased through the year, so the November prices were significantly higher than the March and April prices. Coal prices were relatively flat and much lower than the others.

Variable O&M prices can also differ significantly by plant. The EIA uses a large data set of all existing and planned power plants in the operation of its model used for the Annual Energy Outlook (AEO). The variable operating cost can vary for each, but aggregations can be made to find typical values for different plant types and fuel. In addition, the simulation model can add plants of various types to meet demands in the future, and these plants have assumed variable costs.

Table 4.5. 2004 Electric Utility Average Fuel Prices ($/mmBtu) [5]

2004	Gas	Oil	Coal
March	5.52	4.28	1.30
April	5.76	4.40	1.32
October	6.13	5.15	1.39
November	6.68	5.33	1.39

Table 4.6. O&M Costs Used

	Gas	Oil	Coal
Minimum	0.9	0.9	1.7
Average	2.3	2.8	2.4
Maximum	18.6	18.6	5.7

From the data set used by the National Energy Modeling System (NEMS), the ranges for the variable costs from coal-, gas- and oil-fired plants can be calculated, and are shown in Table 4.6. Because the gas- and oil-fired production could be from a combined-cycle plant, combustion turbine, or steam plant, it becomes more difficult to select the proper values to apply to the plants on the margin. The percent of generation (found by multiplying the capacity and capacity factor for each plant within the database) helps to identify the more likely production types. Typically, turbines are used at higher demand periods, because of their higher heat rates (lower efficiencies). However, with recent increases in gas and oil prices, combined-cycle plants have become more widely used for load following. Higher variable O&M cost will mean a lower relative fuel cost for the same marginal cost, hence a lower heat rate and so less total energy used. Final results, though, are more complex because the answer depends on the type of fuel that ends up being assigned to a system lambda value.

At any given system lambda marginal cost value, it is unknown whether the marginal plant was using coal, oil, or natural gas. For example, a marginal price of $40/MWh could be from an efficient gas-fired plant (with high-cost fuel) or inefficient coal plant (with low-cost fuel). One means of differentiation is that there are minimum heat rates below which it is unlikely that plants can operate. A plant with a heat rate below 6,824 Btu/kWh is operating at greater than 50 percent efficiency. Only a few modern combined-cycle plants can approach that.

The process used to determine which fuel a given system lambda corresponds to was to calculate the resulting heat rate assuming each of the fuels. If the heat rate assuming natural gas was above 7,000 Btu/kWh, then gas was the assumed fuel. If the heat rate assuming gas was below 7,000 Btu/kWh, but the heat rate was above 8,000 Btu/kWh for oil, then oil was the assumed fuel. (The oil threshold was set higher to reflect the paucity of oil-fired combined-cycle plants.) If neither of these thresholds were met, then the production was assumed to be from a coal-fired plant.

The amount of total energy used in each region can be calculated from the above assumptions. Table 4.7 shows the amounts using the average, maximum, and minimum O&M costs, with a breakdown of whether the energy came from gas, oil, or coal. The calculation gives a range 12-19 TBtu, or 0.012 – 0.019 Quads per year.

Table 4.7. Total Energy Saved from EDST with Varying O&M Cost of Plants

NERC Region	w/ Minimum O&M Cost				w/ Average O&M Cost				w/ Maximum O&M Cost			
	Total TBtu	Gas TBtu	Oil TBtu	Coal TBtu	Total TBtu	Gas TBtu	Oil TBtu	Coal TBtu	Total TBtu	Gas TBtu	Oil TBtu	Coal TBtu
ECAR	2.6	0.4	0.0	2.2	2.5	0.4	0.0	2.1	2.4	0.2	0.0	2.1
ERCOT	0.3	0.2	0.0	0.0	0.3	0.2	0.0	0.1	0.6	0.0	0.1	0.5
FRCC	0.4	0.4	0.0	0.0	0.4	0.3	0.0	0.1	1.2	0.1	0.0	1.1
MAAC	1.0	0.9	0.1	0.0	1.2	0.8	0.1	0.1	1.7	0.4	0.0	1.3
MAIN	1.9	0.3	0.0	1.6	1.9	0.3	0.0	1.5	2.0	0.1	0.0	1.8
MRO	0.7	0.0	0.0	0.7	0.6	0.0	0.0	0.6	0.5	0.0	0.0	0.5
NPCC	1.3	1.4	0.0	-0.1	1.3	1.3	0.0	-0.1	1.3	0.9	0.1	0.4
SERC	1.3	0.2	0.9	0.1	2.6	0.1	0.5	2.1	3.5	0.0	0.0	3.5
SPP	0.2	0.1	0.0	0.0	0.2	0.1	0.0	0.1	0.4	0.0	0.0	0.3
WECC-AZN	0.4	0.1	0.0	0.3	0.4	0.1	0.0	0.3	0.5	0.0	0.0	0.5
WECC-CNV	1.2	0.9	0.0	0.2	1.3	0.9	0.0	0.4	3.3	0.0	0.2	3.2
WECC-NWP	1.0	0.1	0.0	0.8	1.0	0.1	0.1	0.8	1.3	0.0	0.0	1.3
WECC-RMP	0.2	0.0	0.0	0.1	0.2	0.0	0.0	0.1	0.2	0.0	0.0	0.2
Total	12.3	5.1	1.1	6.1	13.6	4.7	0.7	8.2	18.9	1.8	0.5	16.6

This wide range is solely from assuming different variable O&M costs of the marginal plants operating during EDST changes in production. Note that even though higher O&M costs reduce the effective heat rate, and so lower the total energy for a given fuel, more of the production fell below the gas and oil heat rate thresholds, and so were assumed to be from inefficient coal plants, raising the overall energy amount. Further work could be done in the future to better establish the plants actually on the margin during these times, and thereby improve the accuracy of the estimate.

Using the ± 40 percent error bounds on the electricity amounts, along with the range in amounts due to different variable O&M costs shown in Table 4.7, the amount of total energy saved could vary between 7.4 TBtu and 26.5 TBtu. (Table 4.8)

Table 4.8. Total Energy Savings with Error Bounds (TBtu)

	- 40%	Expected	+ 40%
Min O&M Cost	7.4	12.3	17.2
Avg O&M Cost	8.2	13.6	19.1
Max O&M Cost	11.4	18.9	26.5

Table 4.9. Electric Utility Average Fuel Prices ($/mmBtu) [6]

	Gas	Oil	Coal
2004	5.92	5.43	1.36
2006	7.24	7.29	1.53

The cost savings calculated directly from the electricity savings and marginal costs of 2004 was $44 million. This amount is the same regardless of the proportions of different fuels that was determined using the different O&M cost estimations. Applying the ± 40 percent error bounds gives a cost saving between $26 million and $61 million. However, fuel prices have increased substantially since 2004. The estimates for 2004 and 2006 from the AEO 2006 for fuels to electric utilities are in Table 4.9. Applying the 2006 fuel prices to the fuel savings from Table 4.7 gives cost savings between $42 million and $54 million, not including any variable O&M cost savings. With ± 40 percent error bounds, the cost savings could range from $25 million to $76 million. With 28 days of EDST, this works out to a savings of ~ $1 million - $3 million per day.

As a check, it is worthwhile to compare the results above to the 1975 DOT study and its estimate of 100,000 barrels of oil per day equivalent savings. Its results showed a savings of 49,200 MWh per day in March and April. The calculations above show savings of 768 GWh in the three weeks of spring. Dividing this amount by 21 days results in 36,600 MWh per day. Using the same assumed efficiency for oil as in the DOT study, this is the equivalent of 73,000 barrels per day of oil equivalent, about three-quarters of the amount from the 1975 study. Of course, little electric power is generated by oil, and the energy savings are mainly from coal and natural gas (Table 4.7).

PART 3

BACKGROUND ON DST AND HIGHLIGHTS OF PREVIOUS DST STUDIES

5 Background

5.1 Brief History of DST

Daylight Saving Time was first suggested in an essay by Benjamin Franklin in 1784 as a way to save candles in Paris, but was not seriously proposed. Until 1883, localities maintained their own time. This created large problems with railroad scheduling and led the railroads to create Standard Railway Time with four time zones across the country. Theoretically, each zone should center on the four longitude lines of 75˚ (Philadelphia), 90˚ (St. Louis), 105˚ (Denver), and 120˚ (Reno). However, many regions preferred a later dawn and sunset, so the boundary lines were drawn farther to the west from the meridians (Figure 5.1). The time zone lines have been modified over time, most often moving the lines farther west so that these areas would be, in effect, instituting year-round DST.

Figure 5.1. U.S. Time Zones [7]

The first serious attempt to institute DST was in Great Britain by William Willit in 1907. It took several attempts, but it was finally accepted in both Europe and the United States during World War I as a means to save energy during the war effort. After the Armistice, the United States dropped it as an official policy, but various states and regions continued to follow it. Through the early and mid-20th century, DST implementation varied. Table 5.1 gives a timeline of the different DST practices in the United States. During World War II, national DST was established again for the war effort, but dropped afterward. To solve the confusion of multiple DST laws, in 1966 Congress passed the Uniform Time Act, which set DST to start on the last Sunday of April, and end on the last Sunday in October.

States could choose to opt out of following DST, depending on whether they were entirely within a time zone or straddled two zones. Arizona, in the western part of the Mountain Time Zone, chose not to follow DST because they prefer an earlier cool evening. Hawaii, closer to the equator and so not as affected by seasonal changes in lighting, chose not to follow DST. Indiana, on the western edge of the Eastern Time Zone and with some counties already using Central Time, chose not to follow DST except those counties in the Central Time Zone. This, in effect, moves the entire state into the Central Time Zone during the DST period. (In 2006, the state will begin following DST, with some modifications of time zone lines.)

In 1973, during the oil crisis, Congress passed the Emergency Daylight Saving Time Energy Conservation Act of 1973 that initially applied DST year-round, starting January 6, 1974. The law was amended during 1974 to revert to Standard Time from the last Sunday in October through the last Sunday in February starting in 1975. The emergency law expired in 1975 and so DST reverted to the earlier schedule in 1976. In 1986, the spring date was advanced to the first Sunday in April, where it stands today.

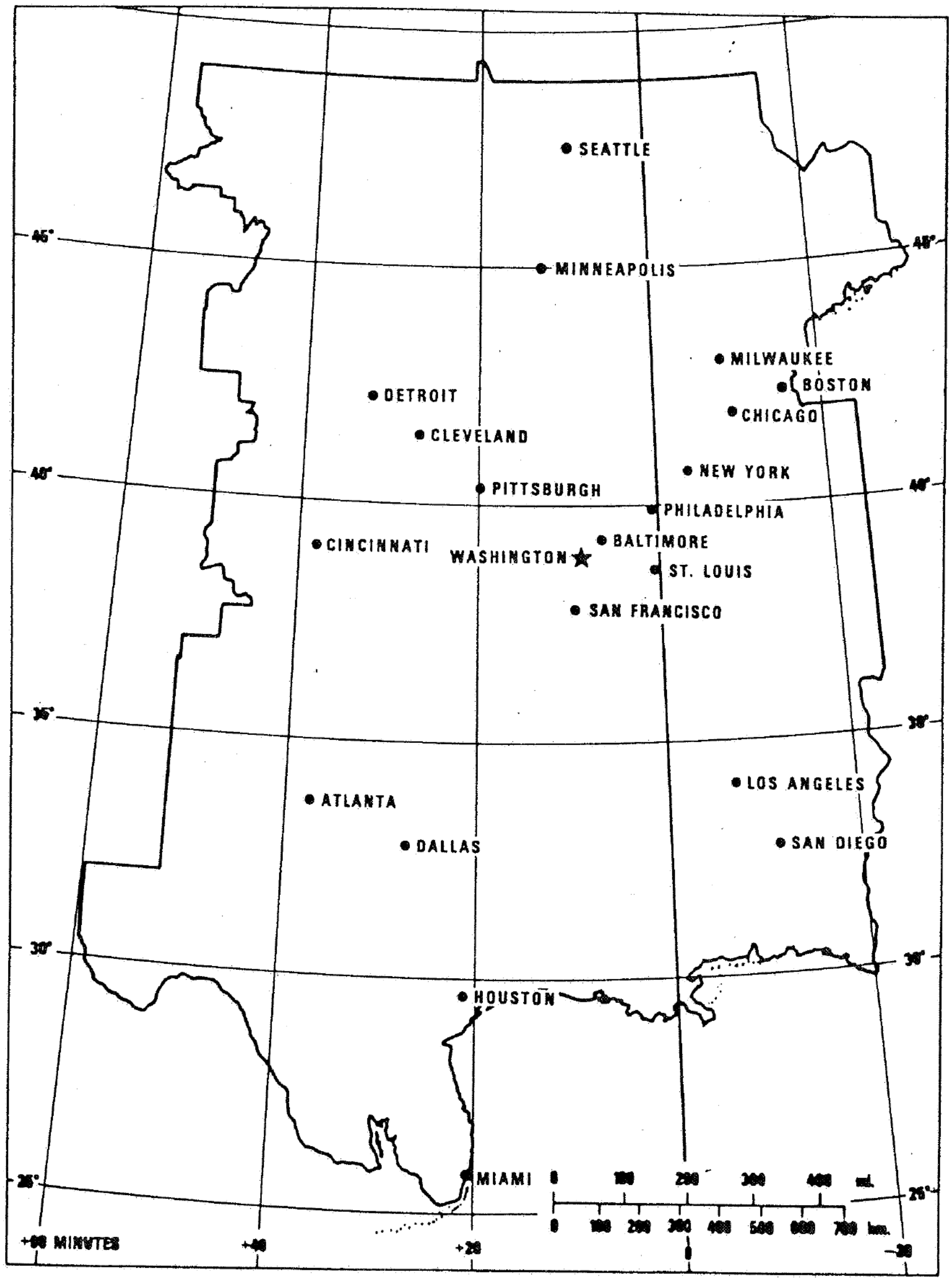
Table 5.1. Timeline of the Dates for DST in the United States [8] [9]

Dates	Dates of DST beginning and end
1918 – 1919	March 31 – October 31
1920 – 1941	Variously observed or not observed in cities and states around the country
1942 – 1945	February 9, 1942 – September 30, 1945
1946 – 1966	May – September, May – October, or no observation, depending on location
1966 – 1973	Last Sunday in April – Last Sunday in October
1974	Jan. 6 – Oct. 31
1975	March 1 – October 26
1976 – 1985	Last Sunday in April – Last Sunday in October
1986 – 2006	First Sunday in April – Last Sunday in October
2007 –	Second Sunday in March –First Sunday in November

The analysis in this study begins with an evaluation of the potential impact of DST on various cities across the country. One factor of importance in calculating the timing of cities' response to EDST is their location within their respective time zone. Further west means a later sunrise and sunset. A 1976 study by the National Bureau of Standards [10] included a chart with the four time zones overlaid, matching the standard meridians (75°, 90°, 105°, and 120°) to indicate how far each city is from the reference line of their time zone (Figure 5.2). The chart shows that most territory lies to the west of the standard meridian, so that most people already face a later sunrise and sunset than if there were no time zones. U.S. cities range from 32 minutes before the standard meridian time to 60 minutes later.

The location of these cities within their time zones is important when assigning representative cities to the different regions of the country, especially those regions that did not have an analyzed city within their boundaries.

Figure 5.2. Overlay of U.S. Time Zones [10]



Note: This map is derived by overlaying the standard meridians (75°, 90°, 105°, and 120°) and setting the meridian to the reference "zero" point to indicate how far each city is from the reference line of their time zone. Axes in the map are longitude in minutes and latitude in degrees.

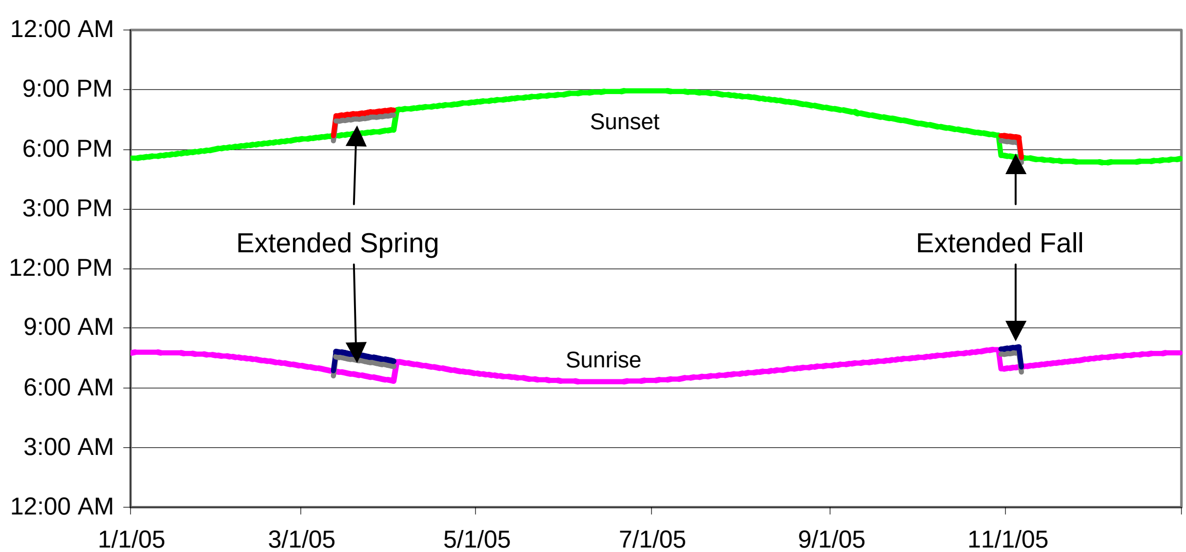
5.2 Energy Policy Act of 2005

Section 110 of H.R. 6, the Energy Policy Act of 2005 [8] reads:

> *(a) Amendment.—Section 3(a) of the Uniform Time Act of 1966 (15 U.S.C. 260a(a)) is amended—*
>
> *(1) by striking "first Sunday of April" and inserting "second Sunday of March"; and*
>
> *(2) by striking "last Sunday of October" and inserting "first Sunday of November".*
>
> *(b) Effective Date.—Subsection (a) shall take effect 1 year after the date of enactment of this Act or March 1, 2007, whichever is later.*
>
> *(c) Report to Congress.—Not later than 9 months after the effective date stated in subsection (b), the Secretary shall report to Congress on the impact of this section on energy consumption in the United States.*
>
> *(d) Right to Revert.—Congress retains the right to revert the Daylight Saving Time back to the 2005 time schedules once the Department study is complete.*

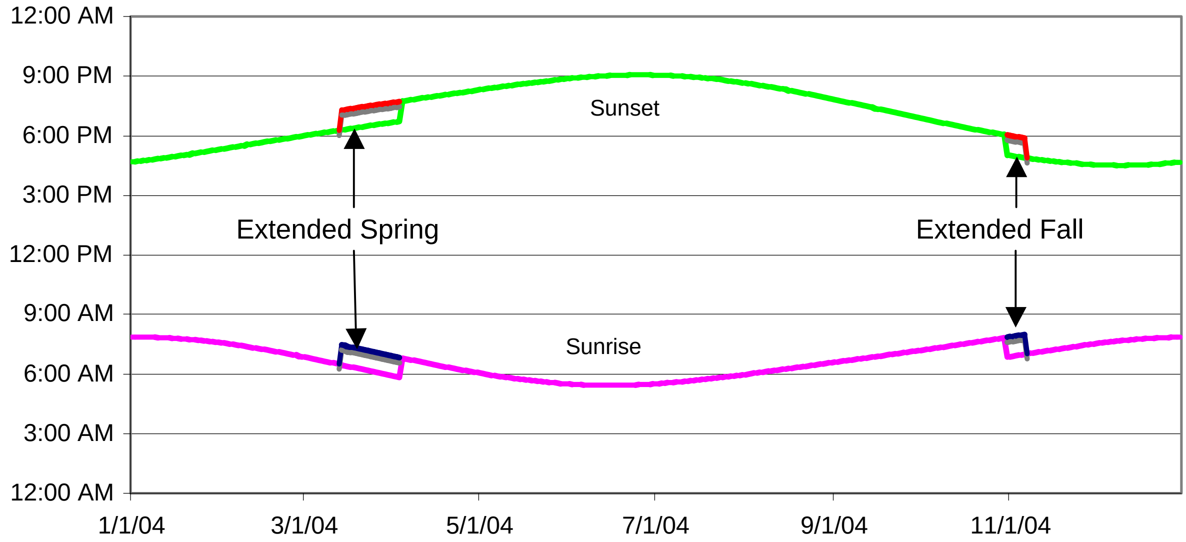
The original House bill extended DST by one month in the spring (first Sunday in April to first Sunday in March) and one month in the fall (fourth Sunday in October to fourth Sunday in November.) During conference proceedings, the dates were modified to the second Sunday in March and the first Sunday in November, for a total of four weeks in most years. However, for the three out of seven years that March has five Sundays, DST will have been extended four weeks in the spring rather than three. Figure 5.3 indicates the sunrise and sunset times for Knoxville, TN, and indicates the time of year that EDST will be in effect.

Figure 5.3. Sunrise and Sunset Times for 2005 in Knoxville, TN, showing EDST



Knoxville is on the western edge of the Eastern Time Zone. Other regions of the country will have slightly different curves. Those in more northern latitudes will have more variation in their sunrises and sunsets, and the lines will not be as flat. Those cities farther east in their respective time zone will have earlier sunrises and sunsets, and the lines will occur at earlier times in the day. Figure 5.4 shows the 2004 sunrise and sunset times for Minneapolis, MN.

Figure 5.4. Sunrise and Sunset Times for 2004 in Minneapolis, MN, showing EDST



The extent of variation and time of occurrence of sunrise and sunset will affect the potential energy impacts of a change in DST as consumption behavior and associated energy demand depends on the extent and timing of the EDST hours relative to consumer behaviors such as lighting, cooking, heating and cooling, and travel.

6 Previous Studies on Energy Effects

While there have been a few studies of the energy impacts of DST, no studies have been conducted that look specifically at the proposed times of the current DST extension (three weeks in the spring, one in the fall). Several studies have looked at year-round DST or at eight-month schedules (March-October); others have looked at adding a second hour of DST, called Double Daylight Saving Time (DDST), during summer months. Some of the analyses provided information on a monthly or seasonal basis. The CEC study [11] provides results on a monthly basis, but only applies the analysis to its own state.

The study results can be used to inform the analysis, and methodologies used are helpful in determining appropriate strategies; however, most of the results are not directly comparable.

6.1 1975 U.S. Department of Transportation Study

When Congress enacted the Emergency Daylight Saving Time Energy Conservation Act of 1973, they required that the Secretary of Transportation prepare interim and final reports on the operation and effects of the Act. The interim report recommended that Congress amend the act to revert to Standard Time for the months of November 1974 through February 1975.

While energy savings was the main purpose for DST, other benefits in safety and crime were also considered to be possible effects. The final report evaluated a number of effects. Table 6.1 is from its executive summary and provides a summary of the results from the study.

Table 6.1. 1975 U.S. DOT Results of DST Impact Studies: The Experimental Eight–Four (Months) System vs. the Historical Six–Six System [4]

Area	DST Impact	Comments
Travel	None perceived by [DOT] techniques; technique would not perceive effect of less than 1.0 percent	Seasonal changes in travel obscure DST effects at DST transitions.
Electricity Usage	Approximate saving of 1 percent or 49,200 megawatts per day for March and April; no evidence of significant peak shaving.	Savings related to DST measured at transitions in October (1973 and 1974), in April (1973), and January (1974)
Gasoline Consumption	None perceived by [DOT] techniques. Estimated maximum possible undetected impact of 0.5 percent of total daily gasoline consumption[40]	Statistical analysis revealed a small DST effect (0.4 percent), which was not statistically significant.
Home Heating Fuel Consumption	Saving of less than 0.1 percent of national demand.	A maximum saving of 3,000 barrels of oil and the equivalent of 5,000 barrels of natural gas per day might occur in south and southwestern states only.
Fatal Motor Vehicle Accidents	Reduction of approximately 0.7 percent or about 50 lives and 2,000 injuries for March and April.	Reduction is observed in a comparison between March and April 1974 (DST) and March and April 1973 (non-DST). Also, spring and fall transition analysis of 1973 provide consistent results.
Fatal Motor Vehicle Accidents of School-Age Children	No special hazard to children compared to the total population at any time of day.	Two studies were conducted. The findings were that during the DST period of January to April, 1974, school-age children did not suffer greater fatalities than those of the total population in accidents involving pedestrian/pedal-cyclists, motor vehicles and their total, at any time of day.
A.M. Radio Broadcasting	0.01 percent loss per station.	
Crime	Evidence of 10 percent to 13 percent reduction in violent crimes in Washington, D.C.	
Advance in School Hours	Essentially no change	A few schools in two West and Midwest states advanced hours where bus routes were long.
Election Day	Increases daylight during existing polling hours in almost all states.	A nine-month system of DST would be required to cover all election days.

[40] Page 99 of the 1975 DOT report, "Based on this analysis, Daylight Saving Time appears to have had no discernible effect on travel demand. If there are subtle influences which DST exerts on travel demand, they are so small, so diffuse, and so intermixed with the effects of other factors that it was not possible for our analytical technique to detect and measure them by using the automatic traffic recorder data furnished by the states. It has been estimated that if there were any effect of DST on travel demand, it would not be greater than plus or minus ½ percent to 1 percent. Such an amount is less than the normally expected week-to-week variation in traffic; but would be significant, if it exists, in analyzing the total energy effect due to DST."

The electric-use analysis involved comparing the hourly electricity data from 15 utilities across the United States, both with and without DST at certain points in the year. The analysis used a procedure of "equivalent day normalization" to isolate the effects of DST from other effects such as weather or economic changes. It separates each day into two parts: one where a potential DST influence is hypothesized (i.e., morning and evening), and one where no DST influence would occur (i.e., midday and night). Similar days were compared (e.g., the first Monday before a DST transition versus the first Monday afterward.) For each pair of days, the DST-influenced parts are compared and the parts uninfluenced by DST are compared. If the value of a parameter has a greater change in the DST-influenced part of the day than in the uninfluenced part, then DST is assumed to be the cause. [4]

Table 6.2. Effect of DST on Electricity Use from 1975 DOT Study. Positive values reflect removal of DST **[4]**

From	% Change in Usage, after vs. before	
DST Transition	Volume I	Volume II
January 1974	- 0.74	- 0.74
February 1975		- 0.65
April 1973	- 1.32	- 0.86
October 1972	+ 0.91	+ 0.91
October 1974	+ 1.76	+ 1.73

Volume I of the report describes the analysis of four transitions to and from DST: January 1974, April 1973, October 1972, and October 1974. Volume II provides more detail and lists five transitions (and gives different values for some). The January 1974 analysis used the hourly demand for the four days prior and four days subsequent to DST, while the other transitions evaluated seven days of data. The percentage change in use they found for each transition is shown in Table 6.2. Note that use went down when entering DST and up when exiting DST. The average of the four values in Volume I is 1.18 percent, and the five values in Volume II is 0.98 percent, which the authors of the study rounded off to report that "electricity usage is consistently less during the DST period at each transition by an average amount of about 1 percent."

It is unclear how the authors arrived at the often-repeated estimate that 100,000 barrels of oil per day would be saved. The Executive Summary table (Table 6.1) lists savings of 49,200 MWh per day, while the report mentions 38,000 MWh per day for the January 1974 transition. Converting electricity savings to oil equivalents, assuming an efficiency of 28 percent (12,000 Btu/kWh) and 6 mmBtu/barrel of oil, the 49,200 MWh per day translates into roughly 100,000 barrels per day.

The study also attempted to analyze the effect of DST on gasoline consumption. Three approaches were attempted: estimates based on behavior and climate, an equivalent day normalization study, and linear-regression models. All of these techniques led to estimates of a few tenths of a percent for the magnitude of the DST effect and were statistically insignificant.

The study examined several modes of home heating-system operation for which savings or losses in fuel consumption are possible as a result of DST. However, there was insufficient information concerning people's operation of their heating systems nor the complementary demographic, climatological, and sociological data required. The report states that a detailed questionnaire to a statistical sampling of households would be required, but an order-of-magnitude estimate of the savings or losses would be very small and not warrant the complete analysis required.

6.2 National Bureau of Standards Review of DOT Study

In 1976, the National Bureau of Standards (NBS) was requested by Congress to review the results of the 1975 DOT study. The review was to focus on four topics: the regional effects of DST, the statistical treatment of school-age children fatal accidents, the DOT analysis of fatal motor-vehicle accidents, and the DOT calculations of electricity savings. [10]

The first major finding of NBS was the strong confirmation with the DOT study of the need for extreme caution in drawing even tentative conclusions because of the substantial technical effort and reliance on extensive data (sometimes faulty) for analyses. The major findings that the review had with regard to the electricity savings were (to quote from the report [10]):

- *The DOT data base, derived from hourly electricity – demand records of 14 power companies (producing approximately 1/3 of the Nation's electrical energy), was found faulty in several respects, and corrections were required.*

- *Applying the analyses used by DOT to the corrected data base, NBS finds no conclusive evidence for decreased production of electrical energy during Daylight Saving Time (DST).*

- *Results from equivalent-day normalization (a technique used by DOT to compare electrical demand between DST and Standard Time periods) were found to be highly sensitive to the choice of morning and evening periods considered to show the influence of DST.*

As part of the examination of the data used by the DOT study, NBS found that only 14 utilities rather than 15 were examined. Approximately 1 percent of the data from the Federal Power Commission had errors, and arithmetical errors in weekly totals were found as well. When corrected, the NBS analysis found that rather than an approximate 1 percent savings from DST, the data analysis gave "a totally inconclusive result."

Furthermore, NBS recommended against the "equivalent-day normalization" technique used by DOT in the absence of definite information on the actual hours of the day that might be influenced by DST. They found that changing the hours of influence and noninfluence could alter the results significantly. DOT assumed an influence period of 11 hours (5 a.m. to 10 a.m. and 3 pm to 9 p.m.). Using a smaller influence period (such as 6 a.m. to 9 a.m. and 4 p.m. to 7 p.m.) could give greater savings, while a larger influence period in the equation could show an increase in demand due to DST. When NBS used the smaller influence period above, they got a 50 percent increase in savings. As an example, they provided a graph showing the percentage change in energy for Tennessee Valley Authority and Southern California Edison using the October 1972 transition data (Figure 6.1). They admit that other utilities may have different curves, depending on their demand, but use these to show the sensitivity.

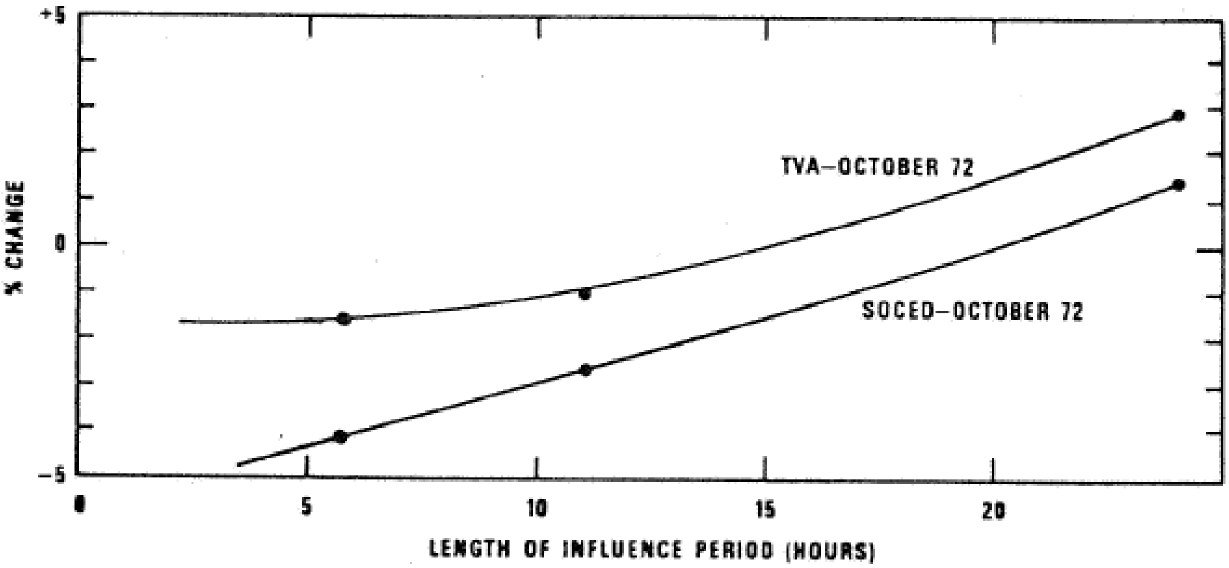
DOT had an opportunity to respond to the NBS review in a Congressional hearing on June 8, 1976. [12] They attached, with their testimony, additional analysis of the data based on the findings of NBS. They found that correction to data and selection of any reasonable influence period in the equivalent day normalization still gave savings due to DST.

In summary, when errors (pointed out by NBS) in the electricity data used by DOT were removed and the equivalent day normalization was applied to the corrected data, the small changes in the results did not alter our original conclusions that:

(1) There is a saving in electricity usage due to DST at DST transitions, and

(2) The magnitude of this DST saving is about 1 percent. [12]

Figure 6.1. Coefficient of Influence as a Function of the Length-of-Influence Period



6.3 University of Kansas Study on Residential Energy Use

In 1996, Brian Rock of the University of Kansas School of Architectural Engineering used the DOE-2 residential building demand model to calculate the potential impact of DST on a typical residential house in different parts of the country. [13]

The DOE-2 code is a well-recognized hour-by-hour simulation model of residential buildings. It can track the annual electrical energy use, electrical cost, natural gas quantity, natural gas cost, and total energy cost. The house modeled was a five-bedroom house built in 1992 in Lawrence, Kansas; and its actual characteristics, operation schedules, and utility bills were used in the preparation of the energy model. Its construction and floor area were typical of many houses built at the time, with a main floor area of 1,100 ft^2, an upper level of 500 ft^2, and a finished basement of 1,000 ft^2. Specifics for the house, such as HVAC system, windows and wall construction, and number of residents, were all based on values for the house.

The code allowed the house to be modeled in 224 locations around the United States. Weather data for each site included hour-by-hour dry bulb, wet bulb, wind speed and direction, cloud cover, and solar data. The DOE-2 code was run in three modes: with Standard Time (ST) year-round, DST only during the summer, and DST year-round. The results showed that for summer-only DST, average annual costs were slightly higher than year-round ST, 0.147 percent. Both electricity and natural gas use increased. Costs for year-round DST were essentially the same as for year-round ST, - 0.0004 percent, with electricity use declining but gas use increasing. So going from summer-only DST to year-round DST saved 0.148 percent in cost, with most savings being in electricity. Table 6.3 shows the electricity, natural gas, and cost differences among the three scenarios. Finer resolution of results was not provided in the paper.

Table 6.3. Average Annual Percentage Difference between Scenarios [13]

	ST to ST w/Summer DST	ST to year-round DST	ST w/Summer DST to Year-round DST
Electrical energy (kWh)	0.244	- 0.022	- 0.267
Electricity cost (US$)	0.228	- 0.012	- 0.241
Natural gas (therms)	0.051	0.024	- 0.027
Natural gas cost (US$)	0.047	0.015	- 0.032
Total energy cost (US$)	0.147	- 0.0004	- 0.148

6.4 California Energy Commission Study

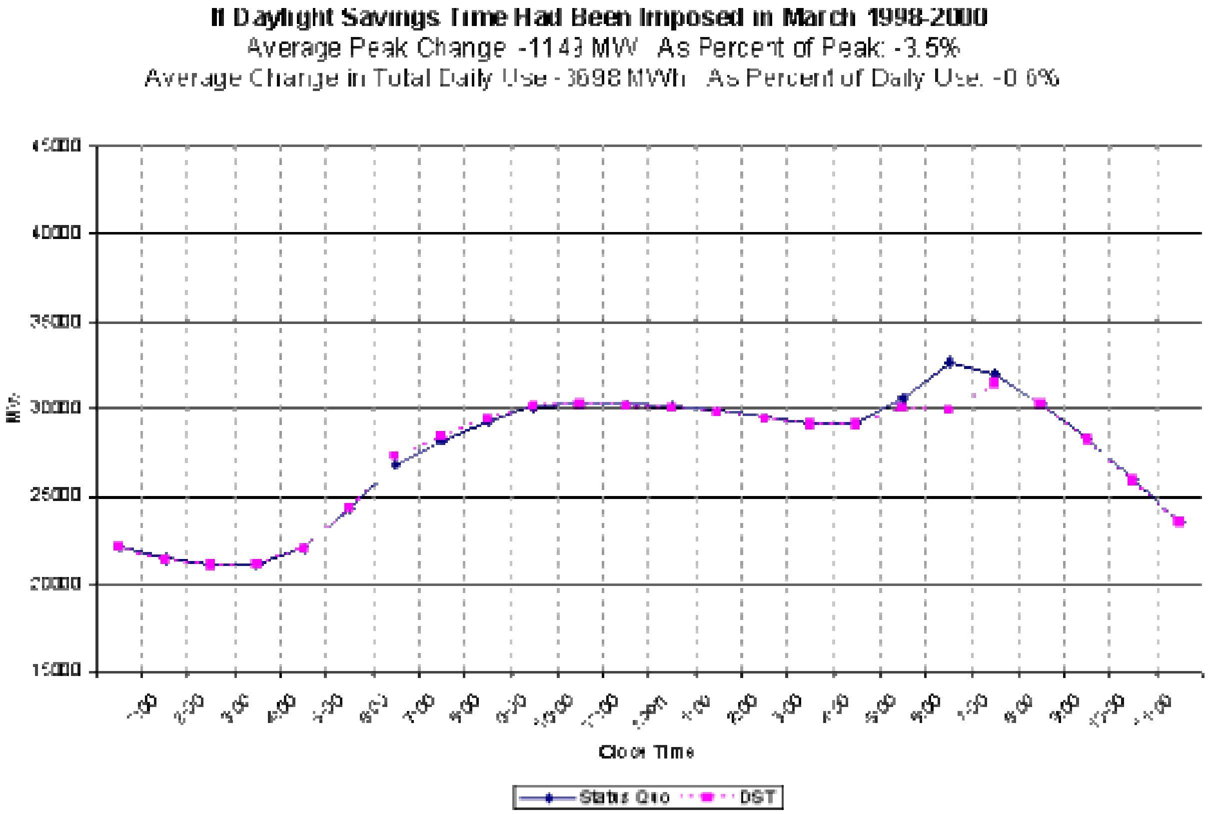
Recently, during the California energy crisis of 2000-2001, the California Energy Commission studied the potential impact of changing the period of DST in California. [11] The study examined both a lengthening of the period of conventional DST (characterized by a one-hour shift from Standard Time) as well as moving to a two-hour shift from ST during the summer months (so-called “Double Daylight Saving Time” or DDST).

The study, undertaken by the CEC, indicated that the energy savings from moving DST up to the beginning of March would be about 0.6 percent of electricity consumption during that period. These estimates were specific to California, and different weather characteristics in other regions of the country—as well as different end-use patterns of electricity use—may yield higher or lower-percentage savings.

The analysts included energy, economic, and weather variables in a statistical formula that evaluated “seemingly unrelated regression” parameters to determine a best-fit approximation of hourly energy use. It is a system of 24 linear equations, one for each hour of the day. According to the authors, “This method was chosen because it allows the estimated relationship between the independent variables and energy use to change throughout the day while taking into account the correlation between energy use over the hours of the day.”

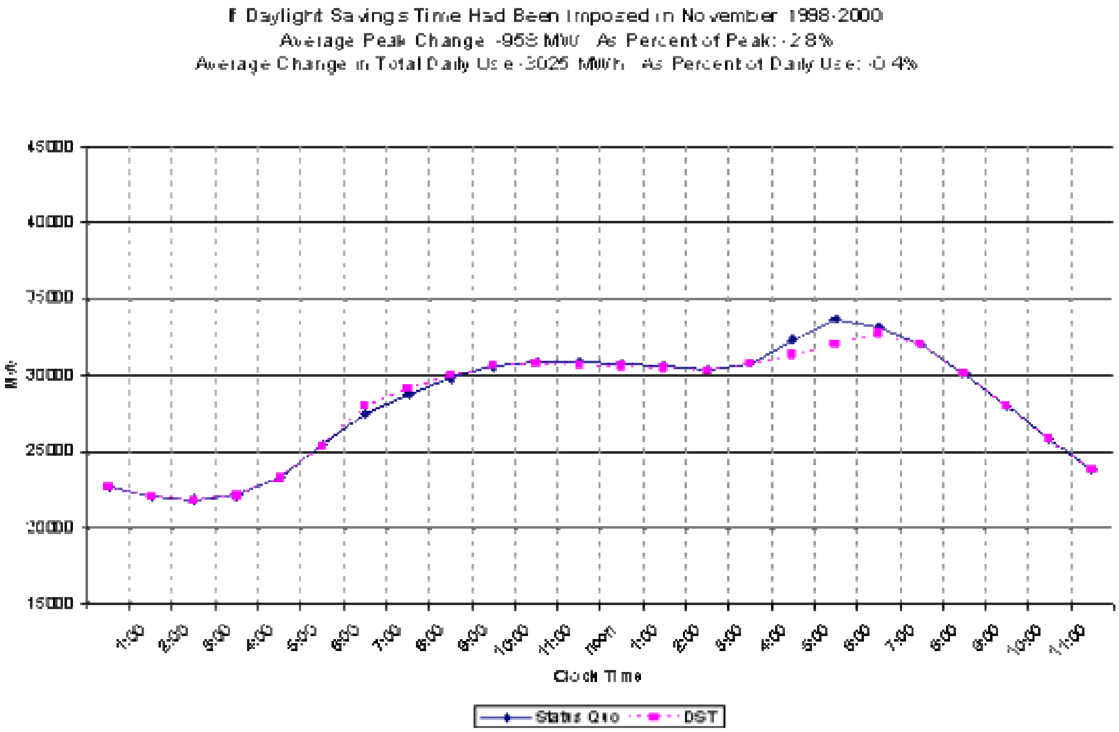
As part of the analysis, the report provided monthly graphs of the weekday electricity profile both with and without the proposed DST. The graph for March (Figure 6.2) is applicable to this study, because it is similar to the time frame of the springtime DST extension. The peak demand between 6 p.m. and 7 p.m. drops 8 percent, with about 2 percent reductions in the hour before and after. The overall system peak shifts to one hour later and drops 3.5 percent, from 32.6GW to 31.4GW. Because California was significantly capacity-constrained (the major reason behind the study), a 3.5 percent reduction in peak demand could make a significant difference in the amount of capacity required. The 1,149 MW difference is about equal to one large nuclear plant.

Figure 6.2. Results of California DST Study for March [11]



Also of interest for this study were the results for November (Figure 6.3). Extending DST through November had less effect on overall energy use, a 0.4 percent reduction, than the March results. The daily peak demand was reduced by only 2.8 percent. The reductions were more concentrated in the 5 p.m. to 6 p.m. period than the 6 p.m. to 7 p.m. hour, reflecting that November is well past the Autumnal equinox, while March is during the Vernal equinox. Sunsets are an hour earlier; e.g., for Los Angeles the sunset on Nov. 4, 2006, is 4:58 p.m., but for March 12, 2006, is 5:59 p.m.

Figure 6.3. Results of California DST Study for November [11]



6.5 EIA Review of the CEC Study

In the summer of 2001, EIA was requested by Congress to analyze the CEC study, with an eye to the feasibility of carrying out this analysis nationwide. EIA provided a letter report and three enclosures in response. [14] The first enclosure was a review of the CEC analysis from a technical perspective. EIA was very complimentary of the CEC effort, recognizing it as an excellent effort at modeling, performed in a relatively short period of time. They identified the following technical questions:

- *The CEC study may understate the uncertainty of the model predictions. (CEC has told EIA that it is pursuing the development of more complete estimates of the uncertainty.)*

- *EIA has concluded that the theoretical model underlying the CEC analysis is based on the assumption that the "residuals" (unobserved "shocks" that cause consumption to be higher or lower than normal) from day-to-day are independent. This is not the case, as is acknowledged in the CEC report. When CEC tried to incorporate day-to-day correlation in their model, it was unable to obtain convergence from the estimation program. This does not bias results, but does increase the variance of predictions.*

- *The CEC model explains consumption in California as a linear function of variables that include weather for six sites and hours of daylight for three sites. While CEC was very careful in their selection of the sites, this high level of aggregation in the consumption data makes it difficult to accurately account for variation due to weather and daylight. The standard error of the residuals for the 24 hourly models range from about 5 percent* *to 0 percent of estimated consumption. EIA believes that a major contributor to the lower level of accuracy in the CEC model is the high level of aggregation. Additionally, in other modeling work, EIA has found that using weighting of input variables (such as weather and daylight in the CEC analysis) to reflect the size of the population exposed to those conditions provides better explanatory power in models.*

They also noted that the analysis was based on historical demands from 1998-2000. With changes in consumption patterns due to conservation, especially considering the energy crisis in California, it may be difficult to apply the historical data to future uses.

The second report provided details on possible options to conduct a broader, national study on energy savings. They provided three options with costs ranging from $50,000 to more than $2 million. The first and largest would apply the California methodology to between 100 and 150 randomly selected utility service areas across the country. This would be the most exhaustive method and would still face methodological issues raised with the CEC study. The second option would conduct case studies of a small number of utility service areas, to illustrate possible extremes in weather and daylight. It may provide ranges of savings, but not a national estimate. The third method would be a comparison of several "paired regions" in adjacent time zones. This was the simplest option, but would also not provide a national estimate. The EIA conducted a paired-region analysis in the third enclosure, comparing the electricity use for Indianapolis, IN (in the Eastern Time Zone and no DST) to Springfield, IL (in the Central Time Zone and with DST.) The results showed no appreciable electricity saving due to DST over the year. (However, the analysis did not address the issue of whether a small extension of DST in the spring and fall might result in savings.).

After their review, EIA concluded: "After reviewing the CEC analysis and considering the alternative approaches, EIA does not believe that any reasonable amount of data collection and analysis would yield estimates of [national] electricity savings from daylight-saving time that would be significant and statistically credible."

Some of these criticisms may apply to this study, which should be considered in future efforts.

6.6 Indiana Energy Use

Prior to 2006, most of Indiana did not follow DST. However, they have often evaluated the issues. In late 2001, the Indiana Fiscal Policy Institute attempted to use the analytical methods of the California study to determine the energy savings in the state.[15] They had difficulty getting the original Seemingly Unrelated Regression equations, based on California's model, to give credible results. They modified the equations to take the general form:

Megawatts = c + *b**(Workday) + *b**(Employment) + *b* *(Temperature) + *b* *(Humidity) + *b* *(Barometric Pressure) + *b* *(Wind) + *b* *(Visibility) + *b* *(Sunrise) + *b* *(Sunset) + *b* *(Morning Twilight) + *b* *(Evening Twilight) + *e*

Where each italicized letter represented a solved-for weighting factor (generically represented by *b*).

Their energy-savings results were in contrast with California, in that electricity consumption appeared to drop during the morning hours due to DST and increase during the additional hour of daylight in the evening. They admitted that the results in their report were neither definitive nor conclusive, and so could not infer that DST in Indiana would either increase or decrease electricity consumption.

6.7 Federal Legislative Hearings

Legislative hearings on DST have provided a forum for a number of authorities who have given testimony on the issues. Most such testimony reiterated the results from the DOT study. For example, in the 1985 hearings concerning extending DST to early April, Neil R. Eisner, assistant general counsel for Regulation and Enforcement, Department of Transportation, gave the following testimony [16]:

> *As I have mentioned, we concluded that daylight saving time holds the potential for electricity savings of 1 percent in March and April, equivalent to roughly 100,000 barrels of oil per day, or about 6 million barrels over the two months. These savings were calculated from Federal Power Commission data for the daylight saving time transitions in the 1974-1975 experiment. Due to this limited data sample, the findings have to be judged "probable," rather than conclusive. Theoretical studies of home heating fuel consumption identified small savings due to daylight saving time. No potential increases in travel demand and gasoline use due to daylight saving time were identified. Overall, the lack of actual data precluded a reliable estimation of total energy savings due to daylight saving time.*

In May 2001, Linda L. Lawson, acting deputy assistant secretary for Transportation Policy, U.S. Department of Transportation, gave very similar testimony on energy savings to the House Science Committee, Energy Subcommittee during hearings concerning Daylight Saving Time and energy conservation [17]:

> *Our 1975 study concluded that daylight saving time might result in electricity savings of 1 percent in March and April, equivalent to roughly 100,000 barrels of oil daily over the two months. These savings were calculated from Federal Power Commission data for only four daylight saving time transitions -- in the winter, spring and fall of the 1974 - 1975 experiment. Due to the limited data sample, the findings were judged "probable", rather than conclusive. Theoretical studies of home heating fuel consumption identified small savings due to daylight saving time. No potential increases in travel demand and gasoline used due to daylight savings time were identified at that time. The lack of actual data precluded an estimation of net daylight saving time energy savings.*

7 Energy and Electrical Use

Both the DOT study and CEC study recognized that the largest energy-saving potential is in the form of electricity, but other fuels may be potentially impacted to a smaller degree. For this reason, the focus of the quantitative analysis in this study is on electricity, but other energy forms should be recognized. Energy is used in the United States for a wide variety of end uses. Some of these may be influenced by DST, while others less so. There may be countervailing influences from DST that could raise the level of some end uses, while lowering others. Behavioral aspects, how people live their lives and change their patterns with the extra daylight, may have a larger potential impact on overall energy-use changes than a static determination of existing energy end use. However, it is worthwhile to understand how energy is used in this country and what relative proportions of energy use are attributed to different activities.

7.1 Annual Energy Outlook Results

The most comprehensive analysis of energy use in the country is that provided by EIA. Each year they release an AEO that provides detailed analysis of both current and projected energy use over the next 20 to 25 years, with the latest being the AEO2006.[6] Energy use at an accumulated level is separated by economic sector (residential, commercial, industrial, transportation) and by energy type (oil, gas, coal, nuclear, renewables). The electrical sector is separately broken out and calculated, giving detailed analysis on types of generating plants built and operated. The analysis is based on a large complex model called the National Energy Modeling System (NEMS). The AEO2006 sectoral breakout of 100 quads of U.S. energy consumption for 2004 is shown in Table 7.1.

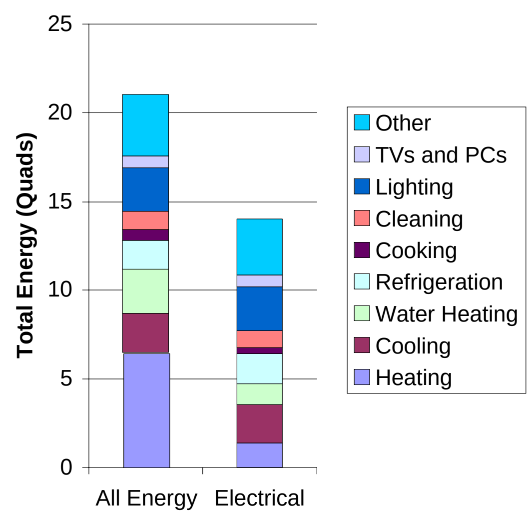
Table 7.1. AEO2006 Sectoral Energy Breakout for 2004

Sector	Residential	Commercial	Industrial	Transportation
Total energy, quads	21.04	17.37	33.27	28.00

7.1.1 Residential

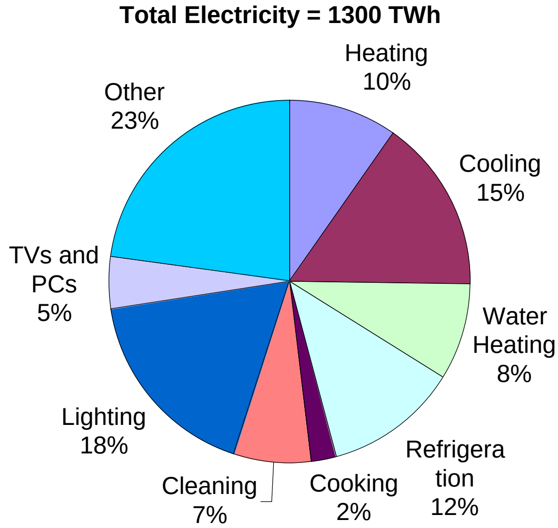
Energy is used in the home for a variety of end purposes. The AEO lists the amount of energy used in the major categories of end uses. Figure 7.1 shows the residential total energy use in Quads (quadrillion Btus). Total U.S. consumption for all purposes was 100 Quads. The “All Energy” column includes electricity, the lost total energy used in making the electricity, and the natural gas/oil/propane/etc. used in the residential sector. The second column shows just the total energy amount used as electricity in the home. Because much of heating and hot water is provided by other fuels, their amounts are much smaller in the second column. The other categories show less change since a higher proportion, if not all, of their

Figure 7.1. 2004 Residential Total Energy Use from AEO2006 [6]



energy comes from electricity. The "Other" category is a mixture of motors, heating elements, and other electronics that are not captured in the major categories. It can include apartment elevators, pool equipment, stereos, and other end uses.

Figure 7.2. 2004 Residential Electrical Use from AEO2006 [6]



Of all the categories, the most affected by EDST is likely lighting. After all, the purpose for changing all clocks by one hour is "day**light** saving." Figure 7.2 shows the relative proportion of electrical use by each of the major categories. Note that, according to the AEO2006, lighting makes up 18 percent of total residential electricity use. During the time of EDST (late afternoons in March and early November), cooling and heating needs are likely not near their peak levels. This means that a significant reduction in lighting needs can have a measurable impact on overall electricity needs during that time.

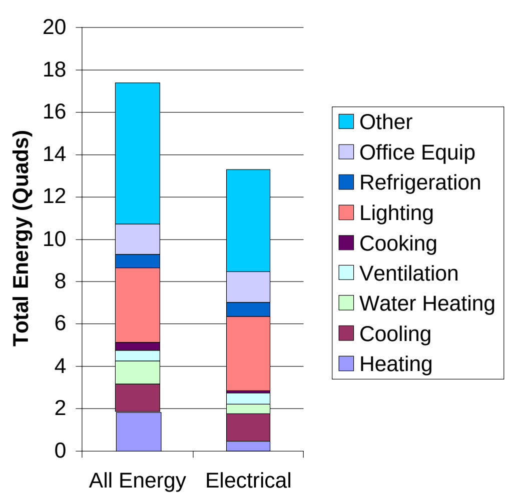
In rooms that receive sunlight, especially south- or west-facing windows, artificial lighting could be postponed until later in the evening, saving energy during those hours. If residents still retire for the night at the same time as without DST, then lights may be on for fewer total hours, and overall energy savings would occur. This may be offset by additional lighting requirements in the morning.

Other possible residential potential impacts are in cooking and other appliance use during the early evening, as people take advantage of the extra daylight. For example, during the Senate hearings on extending DST in 1985, the Barbecue Industry Association projected an increase in charcoal briquette sales of 7-8 percent and a sales increase of some 200,000 grills.[18]

7.1.2 Commercial

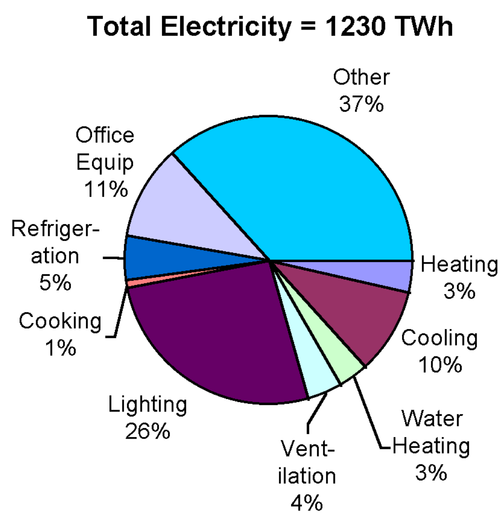
As with the residential sector, the AEO2006 lists the amount of energy used in the major categories of end uses. Figure 7.3 shows the commercial total energy use in Quads. The "All Energy" column includes electricity, the lost total energy used in making the electricity, and the natural gas/oil/propane/etc. that are used in the commercial sector. The second column shows just the total energy amount used in the form of electricity. Heating, cooling, and water heating make up a proportionately smaller portion of the total energy use than in the residential sector; yet, as with that sector, much of heating and hot water is provided by other fuels, and so their amounts are smaller in the

Figure 7.3. 2004 Commercial Total Energy Use [6]



second column. The other categories show less change because a higher proportion, if not all, of their energy comes from electricity. As mentioned above, the “Other” category is a broad array of other uses, not modeled as carefully, that can be ignored relative to EDST effects.

Figure 7.4. 2004 Commercial Sector Electrical Use [6]



Lighting plays an even larger role in the commercial sector than in the residential (Figure 7.4). This category makes up 26 percent of all electrical use (and 20 percent of all energy of any kind) versus 18 percent of residential electric use. Lighting savings could make a large potential impact on overall electrical and energy savings.

Some of the areas where lighting could be reduced through EDST are parking lots, business signs, daylighting inside buildings with interior space having exposure to natural lighting, or parks and recreation. There may be an increase in lighting needs in the few businesses that open early enough for the later dawn to impact them. Street lighting is included in the commercial sector. Most street lighting will not change their total output, but only shift with the change in sunset and sunrise. Some, however, may operate only during evening activities and so may have less energy use with EDST.

Heating and cooling may see small potential impacts as well, either from additional heat required in the morning before solar gain can assist, or reduced heating needs in the late afternoon. There could instead be added evening cooling needs depending on the climate, building solar gain, internal demand, and other factors.

7.2 Residential and Commercial Surveys

One difficulty with the national accumulated economic sector data is the inclusion of “infrastructure” energy in the sectoral totals. To better understand the potential EDST impacts on actual energy used in the buildings sectors (residential and commercial), information from the sectoral survey and analysis results, published at approximately four-year intervals, is helpful. [19] [20]

Energy is used in homes for a variety of end purposes. Over the years, the EIA energy surveys of homes have included breakouts of some end uses of electricity. Table 7.2 shows the end-use breakout analysis results for the 1987, 1990, 1993, 1997, and 2001 residential end-use surveys.

Table 7.2. Percent of Electricity Consumption by End Use

	Survey Year				
End Use	1987	1990	1993	1997	2001
Air-Conditioning	15.8	15.9	13.9	11.8	16.0
Space Heating	10.3	10.0	12.4	11.4	10.1
Water Heating	11.4	11.2	10.3	11.0	9.1
Total Appliances	62.5	63.0	63.4	65.9	64.7

The 2001 Residential Energy Consumption Survey (RECS) provides additional detail on the variety of end uses within the home. A summary of the findings are:

- The largest use of electricity in the average U.S. household was for appliances (including refrigerators and lights), which consume approximately two-thirds of all the electricity used in the residential sector;

- Air-conditioning accounted for an estimated 16 percent, space heating 10 percent, and water heating 9 percent;

- No single appliance dominated the use of electricity. Refrigerators consumed the most electricity (14 percent of total electricity use), followed by lighting (9 percent), clothes dryers (6 percent), freezers (3 percent), and color TVs (3 percent);

Of all the categories, the most affected by EDST is likely lighting. Lighting accounts for about 100 Billion kWh in the 2001 survey, and makes up 9 percent of total residential electricity use. In 2004, there were 114 million households, and a straight ratio of the lighting per household would indicate 107 TWh for residential lighting energy in 2004. This amount is smaller than reflected in the AEO2006 values (227 TWh or 18 percent) for several reasons. Housing on military bases and other federal installations is not included in this total. The AEO results relied on a study by Navigant for its estimates on residential lighting. [21]

The differences point out the difficulty in determining the amount of energy saved from EDST by calculating savings from individual end uses. If even current annual amounts cannot be determined accurately, small changes in each end use would have too great an uncertainty to lead to reliable results. However, both sources show that daylight-sensitive end uses are large enough that there is a potential for energy savings.

7.3 Transportation

In testimony before a Congressional Committee [17], Linda Lawson, a senior U.S. DOT official, noted the need to assess "the potential for increased travel demand resulting from more evening daylight and increased gasoline use." A literature search yielded limited additional information from R&D studies to support or refute the notion of increased travel activity due to extended daylight hours in the evening.[41] Responses are likely to vary by household size and composition,

[41] Benfield [24] suggests that vacationers prefer their daylight in the evening rather than in the morning, suggesting that this will help tourism in California. How this potentially impacts miles traveled or fuel use is unclear.

and by the way in which household members balance the more- versus less-time discretionary types of trip. A number of competing or offsetting forces may be at work, including people who:

- make extra trips at the end of the work day
- drive to work and/or drive home later in the day
- alter their car-sharing or trip-chaining activities

Just how these different behaviors play out in terms of net energy consumption may not be straightforward. For example, spreading out the morning and/or afternoon traffic peaks by starting or finishing work later may reduce traffic congestion and possibly fuel consumption. However, if this behavior precludes spouse or schoolchild pick-ups or other forms of trip-chaining or car-sharing/vanpool activity on the way home, then the net effect may be an increase in fuel consumption. If this less-congested trip-making at the end of the workday induces more trips, it may add to fuel use. If these weekday evening trips replace home-based weekend trips, then depending on the relative trip distances involved from work versus home, more or less fuel may be used in a given week. Given the tremendous changes that have taken place in personal travel activity patterns, including a general increase in trip-making by U.S. households, speculations based on studies much more than a decade old are going to be suspect.

Linda Lawson's 2001 Congressional testimony [17] also notes the potential for the DST shift to impact aspects of transportation supply:

> *Clear and consistent time observance is crucial for maintaining bus, train, and airline schedules. ..... Consistency has become more important over the years with globalization, "just in time" delivery, and the widespread use of computer programs with embedded daylight saving time changeover dates.*

The most vocal group within the transportation industry itself has been the airlines; and, in particular, the Air Transport Association, which said the proposed DST shift, would cause a "significant disruption" to domestic and international airline schedules and give European and Asian carriers a competitive advantage [22].[42]Airlines may also have to modify arrival times to comply with late-night noise abatement programs [23]. Again it is unclear, however, how such changes in scheduling would potentially impact total passenger miles traveled, total aircraft miles flown or the relationship (i.e. number of seats occupied per flight) between the two. How DST shifts will affect the energy used by trucking, barge, and railroad companies are similarly unclear. Where truck movements are concerned, shifts in the timing of passenger traffic might affect the travel fuel as well as time-related costs of freight deliveries within congested urban areas; but such traffic shifts would need to be significant, and existing truck delivery routes as well as time windows would need to be suitably limited. Further state level data, obtained from the Travel Monitoring and Survey and the Florida Department of Transportation indicated that

[42] For example, the apparent clock time of a nonstop flight from Washington to Los Angeles will be three hours instead of two, while the return flight will be seven hours instead of eight.

total travel was not impacted by changes to DST.[43] Other industrial use would likely see little change from EDST. Daylighting is rarely used as a significant proportion of electrical lighting, and lighting is a relatively small proportion of industrial use, compared to residential and commercial sectors.

[43] Florida Department of Transportation's and the Federal Highway Administration's analysis of Florida data on travel patterns associated with changes in daylight saving time.

8 Other Potential Impacts

There are other, non-energy aspects to extending DST that are likely more important to its societal potential impact than the energy savings. Some of the issues that have been raised are:

Children traveling to school during darkness – This issue was studied in-depth in a DOT study and several follow-on studies. It is of most concern to residents in western-most parts of time zones, because of the later sunrise. One point made is that, even if increased accidents may occur in the morning due to darkness, there may be fewer accidents in the afternoon because of the later sunset. Behavioral issues then come into play on the relative caution displayed and number of students near the roadway in the morning hours versus afternoon.

Other traffic accident frequency increases/decreases – This issue is related to the one above, but applies more generally to whether EDST increases the relative morning and/or afternoon traffic accident rates. There have been a number of studies over time of the impact of darkness and Daylight Saving Time on pedestrian and vehicle accidents.[24] [25] [26] [27] [28] [29] [30] These show a reduction in accident frequency with daylight and lowered accident frequency with DST.

Halloween trick-or-treating safety – Disagreement exists on whether children will walk their neighborhood at the same clock-time under DST and so have better lighting, or postpone their excursion until darkness later in the evening. In Senate hearings in 1985, Peter J. Pantuso of the National Confectioners Association entered a statement in support of EDST over Halloween in order to increase the safety for children. [31]

Election-day participation – Some have suggested that increased evening daylight will encourage participation in national elections. However, under the current EDST formulation, national election days will only fall under Daylight Saving Time when November 1 is a Monday. During the next 20 years, this will only occur in 2010, 2021, and 2027.

Crime reduction – The original 1975 DOT study examined the issue of crime reduction. The argument is that early-evening crime rates would decline with better lighting, while early morning is not a high crime period, and so less potentially impacted by the additional darkness. The DOT study found evidence of a 10 percent to 13 percent reduction in violent crime in Washington, D.C., due to DST.

Electronics changeover to new DST dates – Concerns have been raised that computers and embedded electronic chips can have the current DST dates hardwired into their circuitry, making it difficult or expensive to update them to the new standard. One energy-related example is the advanced electricity meters that allow time-of-use pricing. [32] Software such as operating systems would also need upgrading. This can be done currently through automatic software updates that major vendors already provide, but must be implemented by each user.

Airline schedule changes – The airline industry is concerned that changing DST dates makes scheduling more difficult, especially with international flights that follow different DST schedules. The Airline Transport Association has stated that a unilateral U.S. DST extension will cause major operational disruption on as many as 51,000 international flights. [32]

Agricultural work scheduling relative to available daylight – Because much of the daily work in farming is dictated by when the sun is up, DST has sometimes caused problems in the agricultural sector. For example, if a farmer cannot enter a field until enough of the morning dew has evaporated, and also must quit work at a specified clock-time, then an hour of work is lost. For dual-job farmers who perform certain chores or activities before their day-jobs, the loss of that morning hour can cause problems. However, it is difficult to know whether there are specific issues with extended DST over and above the current DST schedule.

These issues have been raised frequently, and the 1975 DOT study attempted to evaluate their potential impact at that time. [4] Table 6.1 summarizes the results of their analysis.

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Appendix A. Measures of Uncertainty

No comprehensive analysis of uncertainty, relative to the magnitudes of the predicted savings for EDST, was undertaken in this study. For this assessment, the focus was on the development of a satisfactory model structure that could provide estimates of the expected savings in different locations in the United States. As discussed in the main body of this report, the empirical results appear to be generally consistent with those obtained by CEC, and show some regional sensitivity as expected due to differences of building thermal loads.

Measures of uncertainty were derived for a selected set of the estimated regression models, which provide a general sense of the confidence on the overall estimated potential savings. In some cases, these derivations blend both the results of the statistical analysis along with limited *a priori* assumptions about the magnitudes of outdoor lighting electricity use that would be affected by DST.

Before turning to the details of the derivation, the nature of the uncertainty that is being measured in this type of analysis should be made clear. When regression models are used for predictive purposes, they typically incorporate two types of uncertainty. The first relates to random disturbances—influences from various factors that are not specifically accounted for in the regression model. These disturbances are assumed to be represented by a random variable following a particular probability distribution (usually a normal distribution). In the models shown by Equations (3.2) and (3.5), this influence is represented by the term u. The magnitude of this uncertainty estimated by a regression model is represented by the standard error of the estimate, also called the model standard error.

The second source of uncertainty relates to parameters describing the particular model being analyzed. The random disturbances (u) just described inhibit an accurate measurement of the "true" parameters of the model. Larger samples will help to reduce this uncertainty, but will never eliminate it.

For some types of forecasting applications, both types of uncertainty are a concern. That would be the case in this context, if measuring the uncertainty surrounding the predicted demand for a given hour of a single day is the goal. Such an application, however, is not relevant for this analysis. The concern here relates only to the *expected* (i.e., average) potential impact that a change in daylight will have on the demand for certain weeks, over the course of many years. In practical terms, that concern translates into asking what the variation of this expected value may be, given uncertainty in the values of the model parameters. The random disturbances, representing factors not included in the model, are assumed to equally affect days with or without DST, and so will have no impact on the expected savings from an extended DST period.

While explicit mathematical formulas can be used to derive the magnitudes of the uncertainty just described, they are not implemented for the model systems (e.g., Seemingly Unrelated Regression (SUR) models) in the EViews software package used in this study. An alternative, and numerically equivalent approach, was to employ the stochastic simulation capability of the EViews software. The capability was applied by setting the model standard error equal to zero and then letting the software take random draws from the joint probability distribution of the estimated model coefficients. For each dependent variable (e.g., normalized load in hour ending at 7 p.m.), predicted values were calculated for each random draw of the corresponding set of coefficients. This process was repeated 20,000 times, yielding statistics for the mean and standard deviation of the predicted demand.[44] The standard deviation becomes a measure of the uncertainty in the predicted demand, resulting solely from the uncertainty of the model's coefficient estimates.

This simulation process was conducted for two cases. The "base" case uses the daylight, temperature, and day-type variables as historically observed. The EDST case changes only the daylight variables corresponding to the revised DST calendar.[45] These variables were illustrated for Los Angeles in Table 3.4.

For each day and relevant hour of the three-week period that would have been impacted by EDST in the spring (March 14 through April 3, 2004), the software generates (from the 20,000 simulations) four values for each day:

L(Base) = mean value of the predicted load for base daylight conditions (i.e., current law)

L(EDST) = mean value of the predicted load for the EDST daylight conditions

SE(Base) = standard error of the predicted load (Base)

SE(EDST) = standard error of the predicted load (EDST)

For each day, the change (Chg) in the mean load that results from EDST is[46]

Chg (EDST) = L(Base) – L(EDST)

The real issue, however, is the statistical significance of that measure, given that coefficients of the load models are imprecisely measured. A measure of the standard error of the *change* in the demand can be derived by applying the conventional formulas for the variance of the difference

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[44] The standard deviation of the predicted demand is also referred to as the standard error (SE) of the prediction, a convention that will be used below.

[45] From the discussion in Section 5, EDST would be anticipated to also cause some increase in average temperatures during the evening hours. Thus, by ignoring temperature, the predicted change in the demand *during these hours* will be biased to some extent. The argument presented earlier is that the bias is likely to be largely offset in non-modeled hours where temperatures will be lower than the base case. Thus, for purposes of predicting the impact of EDST, the method focuses only on how changes in daylight will potentially affect electricity consumption. Another issue is whether other variables, not explicitly defined in the model but implicitly included as part of the random disturbance of the regression, are correlated with daylight. The approach taken in the study is that these effects are likely to be small and so, to simplify the analysis, they have been assumed to be independent of the included variables. To the degree to which there is some correlation, the estimated impacts from EDST would be overstated.

[46] In more formal mathematical notation, let X be the matrix of explanatory variables (a constant, daylight, temperature, and day type) and b be the vector of estimated coefficients. The predicted value of the demand or load, L(Base), is then given by the matrix multiplication formula L(Base) = X b. In the EDST case, the matrix of explanatory variables is X^*, where only the daylight variables are different from those in the base case. Thus, in this case, the predicted values of the demands are given by: L(EDST) = X^* b. The standard deviations of L(Base) and L(EDST) are derived by simulation, by drawing various coefficient vectors, b, from the statistical distribution emanating from the regression procedure.

in two independent random variables. The variance (Var) of the difference, as well as the sum of two independent random variables (X and Y), is

$$\text{Var}(X - Y) = \text{Var}(X) + \text{Var}(Y) \quad \text{and}$$

$$\text{Var}(X + Y) = \text{Var}(X) + \text{Var}(Y)$$

Because the standard deviation is defined as the square root (SQRT) of the variance, the standard deviation (or error) for each day's predicted demand savings can be computed as follows:

$$\text{SE(Chg)} = \text{SQRT}\,[\,(\text{SD(base)})^2 + (\text{SD(EDST)})^2\,] \qquad \text{(A.1)}$$

While the model is estimated on a daily basis, the relevant variable in the study is the expected savings for the entire period in which EDST will affect energy demand. The standard error of the *average* of the daily differences can be computed as the square root of (1/(n-1)) times the sum of the squared values for SE(chg). For example, in the calculations for the spring, there are differences for 21 days. Let an intermediate variable, Z, be defined as

$$Z = [\text{SE(Chg)}_1]^2 + [\text{SE(Chg)}_2]^2 + \ldots\ldots + [\text{SE(Chg)}_{21}]^2 \qquad \text{(A.2)}$$

where the subscripts 1, 2, … 21 represent the days in the spring that EDST is in effect. The standard error of the average (mean) change is then given by:

$$\text{SE(Ave Chg)} = \text{SQRT}\,(Z/20) \qquad \text{(A.3)}$$

Table A.1 uses Los Angeles as an example to show a detailed derivation of the confidence intervals for the predicted savings from EDST. The top panel of Table A.1 shows these averaged values for the three evening hours for Los Angeles (for models estimated in the spring of 2004). The top left value shows the mean change in the normalized load over these March days as equal to -0.0276.[47] When translated into percentage terms, the reduction is 2.68 percent for that hour, corresponding to the results shown earlier at the bottom of Table 3.4.

The mean SE (standard error) shown in Column 3 of Table A.1 corresponds to the *change* in the normalized average demand, not the absolute value of the demand. To reiterate, this value is the standard error of the mean change in the normalized load (as calculated from the daily standard errors by Equations A.2 and A.3). The mean RSE shown in the next column is the ratio of the standard error to the mean change in the demand. In the first hour, the RSE of 46.9 percent (= 0.0129/0.276) is relatively large, reflecting the statistical imprecision of the daylight coefficient for that hour. RSE is perhaps the best single measure from which to compare the precision of various estimates.

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[47] For the reasons discussed in Section 5.1.2, the use of the normalized load specification was judged to offer a number of advantages over the modeling of absolute demands, not the least of which was visual transparency as to the impact of daylight on the demand. Unfortunately, that transparency suffers in the derivation of confidence intervals and uncertainty measures. While the normalized load is actually a unitless quantity, this metric can be thought of as involving a certain number of MWh throughout the remainder of discussion of Table A.1. With proper accounting, the sum of changes in the normalized loads across different time periods of the day can be translated into average changes in MWh.

With these statistics in hand, one can then compute the confidence intervals for the change in the (normalized) load for the 5 p.m. to 6 p.m. hour. For the analysis here, a two-sided confidence interval (uncertainty range) has been set at a 90 percent level. In other words, 90 percent of the models estimated with similar data sets would yield an expected change in energy demand between the lower and upper limits. For the application to the evening hours, the lower confidence limit is defined as the lower level of the arithmetic change. Thus, the lower confidence limit provides an upper bound of the electricity *savings*, and the upper confidence limit generates a lower bound for the savings. Applying a critical value of 1.67 from the Student's t-distribution (for 60 observations), the lower and upper confidence limits are, thus, computed as[48]

Lower confidence limit = Mean Change in Load - 1.67 * SE(Ave Chg) (A.4)

Upper confidence limit = Mean Change in Load + 1.67 * SE(Ave Chg) (A.5)

In typical parlance, the right-most values in Line 1 of Table A.1 imply a 90 percent probability that the expected change in the (normalized) load lies between -0.0491 and -0.0060.

The values in Lines 2 and 3 of the tables for the next two hours are computed in the same manner. The high statistical significance of the daylight variable for the 6 p.m. to 7 p.m. hour, as shown earlier in Table 3.3, is reflected in the low value for the RSE of the mean change for that hour (10.4 percent). That result, in turn, leads to a relatively small confidence interval for the average change in the normalized load (-0.1204 to -0.0848).

In this study, the total change for the evening is more crucial than the changes for individual hours. Because the normalized loads in each hour are computed relative to the same reference demand, the changes can be added to yield the total change for the evening. That sum (-0.1713) is highlighted to the right of the text, "Sum (Total Evening)" in Table A.1.

With respect to the total change in the demand for the evening hours, the method employed here recognizes that the estimated changes in the demand for the individual hours are developed from independently estimated models.[49] If the estimates are statistically independent (or at least can be approximated as such), the variance of the sum of changes for the three hours can be calculated by summing the individual hourly variances. The standard error is then computed by taking the square root of this summation, yielding a value of 0.0188, as shown in Table A.1.[50] The 90 percent confidence interval is subsequently calculated using the expressions in Equations (A.4) and (A.5). Expressed in percentage or relative terms, the limits of the 90 percent confidence

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[48]The critical value is taken from the Student "t" distribution, as the actual variance is unknown and is replaced by the estimate from the sample. For further discussion, see any basic text on regression methods.

[49]The use of the SUR estimation method is designed to account for the correlations in the disturbance terms from one hour to the next. The standard errors in the predictions, resulting solely from the model coefficients, are judged to be essentially independent from one hour to the next. To determine the predicted demand (or change in the demand from EDST) for a specific day and year, some explicit accounting for the correlation in the disturbances between hours would be required (as pointed out by EIA in an initial review of this study).

[50]In terms of the values for the three evening hours, the standard error of the sum is the square root of the quantity $(0.0129)^2 + (0.0107)^2 + (0.0085)^2$.

interval are +/- 18 percent of the expected value of the total evening change in the demand. In more condensed language, the uncertainty range is between +/- 18 percent.

Table A.1. Derivation of Confidence Intervals for Los Angeles, Using Models for Spring 2004

Evening

Hour	Mean Chg. of Normalized Load	Mean % Chg.	SE (Mean)	RSE of Mean Change (%)	Lower 90% Confidence Limit - Chg.	Upper 90% Confidence Limit - Chg.
5 - 6 PM (Hour 18)	-0.0276	-2.68%	0.0129	46.8%	-0.0491	-0.0060
6 - 7 PM (Hour 19)	-0.1026	-9.61%	0.0107	10.4%	-0.1204	-0.0848
7 - 8 PM (Hour 20)	-0.0411	-3.84%	0.0085	20.7%	-0.0554	-0.0269
Sum (Total Evening)	-0.1713					
Calculated with variance formula for sum:			0.0188	11.0%	-0.2027	-0.1399
(Confidence intervals expressed as percentage difference from mean ->					18%	-18%

Morning

Hour	Mean Chg. of Normalized Load	Mean % Chg.	Mean SE	RSE of Mean Change (%)	Lower 90% Confidence Limit - Chg.	Upper 90% Confidence Limit - Chg.
5 - 6 AM (Hour 6)	0.0087	0.99%	0.0049	56.5%	0.0005	0.0169
6 - 7 AM (Hour 7)	0.0310	3.25%	0.0113	36.5%	0.0121	0.0499
Sum (Total Morning)	0.0397					
Calculated with variance formula for sum:			0.0123	31.1%	0.0191	0.0603
(Confidence intervals expressed as percentage difference from mean -->)					-52%	52%

Day

	Weighted Change - Normalized Load	% Chg. For Day	Mean SE	RSE of Mean Change (%)	Lower 90% Confidence Limit - Chg.	Upper 90% Confidence Limit - Chg.
Evening	-0.1867	-0.78%	0.0205	11.0%	-0.2210	-0.1525
Morning	0.0352	0.15%	0.0109	31.1%	0.0170	0.0535
Day	-0.1515	-0.63%				
Calculated with variance formula for sum:			0.0232	15.3%	-0.1903	-0.1127
(Confidence intervals expressed as percentage difference from mean -->)					-26%	26%
Confidence Limits for Daily % Chg.					-0.47%	-0.79%

Notes:

(1) Mean change (Chg.) and standard error (SE) calculated over 21 days: March 14 - April 3.

(2) Weights are based on the ratio of the evening and morning reference loads to the average hourly load for the day. The evening weight is 1.090; the morning weight is 0.888

The confidence intervals for the morning hours are much larger in relative terms than those for the evening, reflecting the less precisely estimated coefficients for the daylight variables (see Table 3.3). When the variance formula for the sum is employed, the formula yields limits of +/- 52 percent.

The bottom third of Table A.1 shows the derivation of the confidence interval for the *daily* savings, using the aggregated changes for the evening and morning periods. The first step is to adjust for the fact that evening and morning normalized loads are based on different reference demands. The reference demand for the evening in Los Angeles during this time of the year is about 20 percent higher than that for the morning. To combine the morning and evening impacts, the reference demands and the estimated changes relative to those demands were adjusted by normalizing to the average hourly demand over the entire day. Using the observed demands over the March 14-April 3 time frame, this step involved multiplying the evening and morning changes in Column 1 of the table by factors of 1.090 and 0.888, respectively. When translated into percentage terms, and dividing by 24 to represent the total daily savings,[51] the results show a - 0.78 percent change in daily consumption accounted for by the evening hours, offset by 0.15 percent increase per day from the morning hours. These figures match those in Table 3.3.

The application of the variance formula for the sum of the evening and morning variances yields an uncertainty range of +/- 26 percent for the entire day. When these values are used to multiply the expected daily percentage change of 0.63 percent, the lower and upper 90 percent confidence limits of the potential daily energy changes are computed to be - 0.47 percent and - 0.79 percent, respectively.

As is evident by the explanation of the values in Table A.1, the procedure to derive an appropriate measure of uncertainty for the daily average changes in the system demand from DST is rather complex. Moreover, the results for Los Angeles lend themselves to a full application of this method, because satisfactory models for both the evening and morning hours were obtained.

The formal estimation of confidence intervals was carried out for three other locations—Detroit, Dayton, and Atlanta. Given these results, an overall estimate of the uncertainty range for national electricity savings was determined. Estimates of the uncertainty range for potential national savings included an assessment of the models for which confidence intervals were not formally derived, as well as other factors not considered by the regression approach.

Table A.2 summarizes the uncertainty ranges for the four selected locations. The top row for each location shows the point estimate for the percentage change in the daily demand, repeating the values shown in Table 3.8. Beneath each value is the uncertainty range (or relative confidence limits) evaluated at a 90 percent level of confidence. Thus, for example in Dayton, the uncertainty range in the *daily* demand due to the EDST impact during the evening hours is estimated to be +/- 17 percent. The resulting confidence limits for the percentage reduction in the average daily demand due to the evening hours is 0.46 percent to 0.64 percent (e.g., (0.83 * 0.55 percent = 0.46 percent and 1.17 * 0.55 percent = 0.64 percent).

All of the relative confidence limits are calculated using the method as discussed in detail for the Los Angeles results. This method assumes independence of the estimated values for the hours considered, and uses the formula for the variance of a sum to calculate the variance (and, subsequently, the confidence limits) for expected total daily savings.

[51] The hourly changes, normalized to the average hourly demand for the day, are divided by 24 to convert to average daily savings. Thus, for example, if hourly demands were constant across the day and there were changes of + 1 percent during six hours, the average daily change would be (6 x 0.01)/24 = 0.0025 = 0.25 percent.

As discussed previously, and implied by the low t-statistics for the daylight variables, the uncertainty ranges for the morning change in the demand are considerably higher than those for the evening hours. In several cases (Dayton and Atlanta), this range at the 90 percent level of confidence includes values between zero and double the estimated value. Further study, including perhaps information collected on a sub-hourly basis, is needed to better measure this potential impact from DST.

Depending on the relative magnitude and precision of the morning demand predictions, the confidence limits for the daily average savings will be affected. Clearly, the relative uncertainty for Atlanta is significantly higher than the other locations, with uncertainty ranges of +/- 49 percent of the point estimate. Because the estimated savings for all of the other locations in the South appear to be approximately the same (with generally imprecise coefficient estimates as to how daylight would affect the morning demands), it could be expected that these other locations may also have uncertainty ranges greater than 40 percent.

To conclude this discussion, even this limited application of the uncertainty methodology appears to provide some useful ranges from which one may set an overall confidence interval for the national level estimates. With the exception of Detroit, uncertainty ranges for the other locations are between +/- 24 percent to +/- 49 percent. Accordingly, a reasonable, and perhaps conservative, estimate of the overall uncertainty range for nationwide electricity savings was determined to be +/- 40 percent. This range is used in the body of the report as a means of bounding the national estimates of electricity savings from the implementation of EDST.

Table A.2. Uncertainty Ranges (90 percent Confidence Level) for Predicted Percentage Changes in Systems Demands for Selected Locations—for Spring 2004 Demand Models

Location		Morning	Evening	Day
Detroit	% Change in demand due to:	0.09%	- 0.64%	- 0.56%
	Uncertainty range:	(+/- 80%)	(+/- 11%)	(+/- 17%)
Dayton	% Change in demand due to:	0.06%	- 0.55%	- 0.49%
	Uncertainty range:	(+/- 128%)	(+/- 17%)	(+/- 24%)
Atlanta	% Change in demand due to:	0.08%	- 0.32%	- 0.24%
	Uncertainty range:	(+/- 107%)	(+/- 29%)	(+/- 49%)
Los Angeles	% Change in demand due to:	0.14%	- 0.76%	- 0.63%
	Uncertainty range:	(+/- 52%)	(+/- 18%)	(+/- 26%)

Appendix B. Electricity Demand (Load) Regression Results for Selected Utilities

Section 3 presented detailed plots and regression results for Los Angeles, as a means of illustrating the approach used to estimate the potential savings from EDST. This appendix presents plots of hourly demands and regression results for several additional utilities, based on data from spring 2004. The selected utilities display different responses with respect to temperature for this sample period. Portland (Portland General Electric) is normally in a heating mode during the DST transitions; the demands generally have a negative relationship with temperature. There is less electric heating in Detroit (Detroit Edison), and the response of the demands to changes in daylight is relatively large. The demands for the Texas utility show a positive relationship with temperature as cooling is the predominant use of electricity during the weeks around the DST transitions.

B.1 Portland, Oregon

Portland, Oregon, is served by the Portland General Electric utility. Figure B.1 shows the demand vs. temperature plots for morning, day, and two evening hours for the March-April 2004 time period. As with many other locations in the Pacific Northwest, the large share of low-cost hydroelectric power has resulted in substantial use of electricity for space heating. As the plots show, heating is the dominant weather-sensitive demand during this portion of the year. With only a few exceptions, the scatter of data reflect higher demands with lower temperatures.

Figure B.2 shows the normalized demand plots for the four evening hours beginning with the 5 p.m. to 6 p.m. hour in the upper-left chart. For this hour, a small decline in the demand is discernable. As Portland is farther west in the Pacific Time Zone than Los Angeles, it also shows daylight during this entire hour for all of March. The plots for the next three hours show very good correspondence with the daylight variable as constructed. In the 7 p.m. hour, the daylight gradually increases before the April 4 DST transition, reaching 100 percent just before that date. The normalized demands are consistent with this pattern—clearly falling throughout all of March and then remaining constant during April. Exactly the opposite pattern is displayed for the 8 p.m. to 9 p.m. hour. During March (with Standard Time), there is no discernable change, as it is dark during the entire hour. After DST, the gradually later sunsets yield more daylight during the hour, which results in declining demands shown for that hour.

Table B.1 reports the estimated coefficients and standard errors for the key variables—daylight and temperature. The last week of April was omitted from the estimation period as temperatures reached into the 80s, significantly higher than during the earlier March and April days. For Portland, the normalized load equations were included for all four hours (as shown in Figure B.2). As expected, the signs on the temperature difference variables are all negative. The estimated coefficients for daylight variables for the middle two hours are highly significant, consistent with the very distinct trends and abrupt drops in the normalized loads shown in Figure B.2b and c. The daylight coefficients for the hours ending at 6 p.m. and 9 p.m. are much smaller and just meet normal criteria for statistical significance (again, visually corroborated by observation of the normalized load plots).

Figure B.1. Demand vs. Temperature for Weekdays in March-April 2004 for Portland, OR

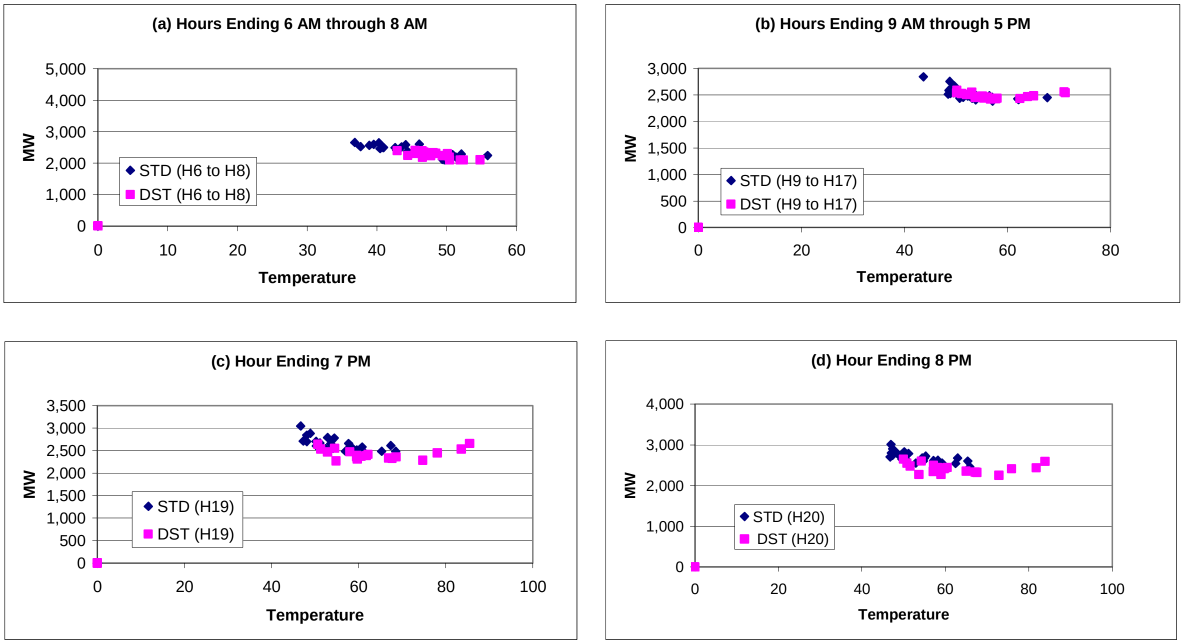


Figure B.2. Normalized Loads for Evening Hours, March-April 2004 in Portland, OR

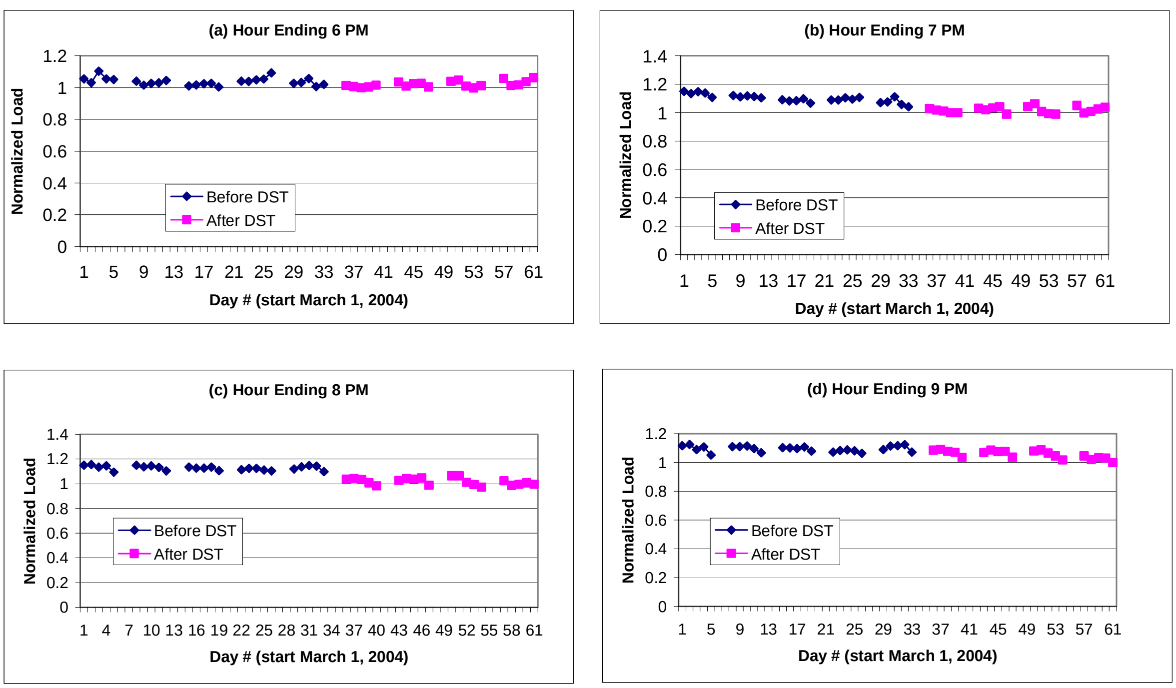


Table B.1. Estimated Coefficients for Key Variables for Spring 2004 Normalized Load Model—Portland, OR

System: SYS1821ARSUR
Estimation Method: Seemingly Unrelated Regression
Date: 02/07/06   Time: 22:14
Sample: 2 54
Included observations: 54
Total system (balanced) observations 212
Iterate coefficients after one-step weighting matrix
Convergence achieved after: 1 weight matrix, 38 total coef iterations

	Coefficient	Std. Error	t-Statistic
Variables - Hour 18			
Constant	1.0774	0.0117	92.0
Daylight19	-0.0378	0.0139	-2.7
Tdiff_18	-0.0051	0.0009	-5.8
Variables - Hour 19			
Constant	1.1792	0.0159	74.3
Daylight19	-0.1316	0.0190	-6.9
Tdiff_19	-0.0053	0.0010	-5.2
Variables - Hour 20			
Constant	1.1219	0.0044	253.3
Daylight20	-0.0852	0.0047	-18.1
Tdiff_20	-0.0044	0.0010	-4.4
Variables - Hour 21			
Constant	1.0815	0.0046	235.3
Daylight21	-0.0448	0.0174	-2.6
Tdiff_21	-0.0019	0.0010	-2.0

As for Los Angeles, the daylight coefficients for the evening hours display statistically significant dissimilarity. For Portland, as well as Los Angeles, the potential impact of increased daylight has its greatest potential impact in the (6 p.m. to) 7 p.m. hour. For Portland, the magnitude of the coefficients for the 7 p.m. and 8 p.m. hours are about 20 percent lower than those for Los Angeles. Thus, these coefficients will imply lower predicted percentage electricity savings in Portland for the upcoming change in the DST calendar.

For the morning hours, only a marginally satisfactory model could be estimated. The normalized loads for the 6 a.m. and 7 a.m. hours have a significant week-to-week variation that seems to be unrelated to changes in daylight.

B.2 Detroit

Detroit, Michigan, as well as surrounding counties to the north of the city, is served by the Detroit Edison utility. Figure B.3 shows the demand vs. temperature plots for morning, day, and two evening hours for the March-April 2004 time period. The responses of electricity use across a wide range of temperatures are fairly small, as most space heating in this region is supplied by natural gas. The plots clearly show lower demands during the two evening hours in the April

DST periods, as compared to days with the same temperature in March. There appears to be some detectable reduction in the demands, averaged over the three morning hours, and no evident difference during the day.[52]

Figure B.4 shows the normalized load plots for the four evening hours beginning with the 5 p.m. to 6 p.m. hour in the upper-left chart. For this hour, no decline in the demand is discernable. The plots for the next three hours show very good correspondence with the daylight variable as constructed. In the 7 p.m. hour, the percentage daylight increases for the first two weeks of March before reaching 100 percent by mid-month. Nevertheless, there still appears to be a stepped decline in consumption after the DST transition on April 4. For the hour ending at 9 p.m., there is no daylight until the DST transition; for the remainder of April, the demand continues to fall as fraction of daylight during the hour increases from about 30 percent to 80 percent (i.e., an increase of approximately 30 minutes).

Table B.2 reports the estimated coefficients and standard errors for the key variables—daylight and temperature. For Detroit, the normalized load equations were estimated as a system for three hours (as shown in Figure B.4), starting with the hour ending at 7 p.m. In the equation for that hour, daylight variables were included for both 7 p.m. and 8 p.m. As expected, the signs on the temperature difference variables are all negative, but are lower in magnitude and statistical significance as compared to Portland.

Figure B.5 shows the normalized load for three morning hours over March and April of 2004. A satisfactory regression model was estimated only for the 6 a.m. to 7 a.m. hour. The plot clearly shows some reduction in the normalized loads during March and then a perceptible increase in the first week after the DST transition. Based on the regression model, the increase in morning demands was estimated to be about 2 percent during the period covered by the EDST (as reported in Table 3.7).

[52] The two days with distinctly lower demands, especially during the morning and daytime hours, are Good Friday and the Monday after Easter.

Figure B.3. Demand vs. Temperature for Weekdays in March-April 2004 for Detroit

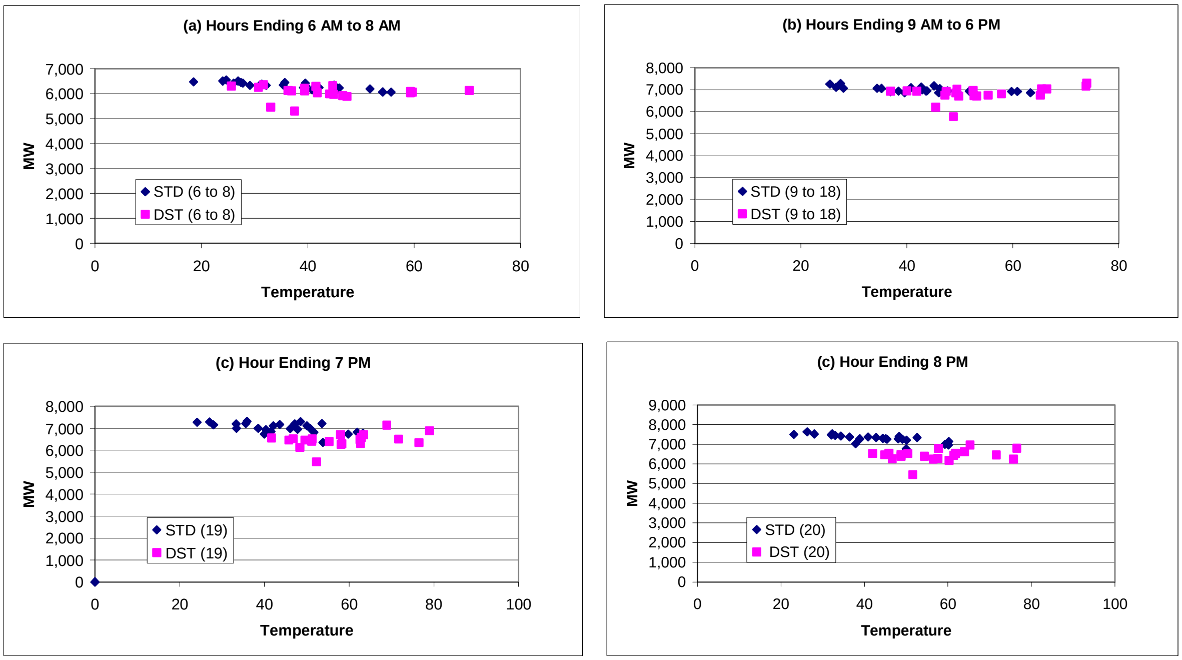


Figure B.4. Normalized Loads for March-April 2004 in Detroit

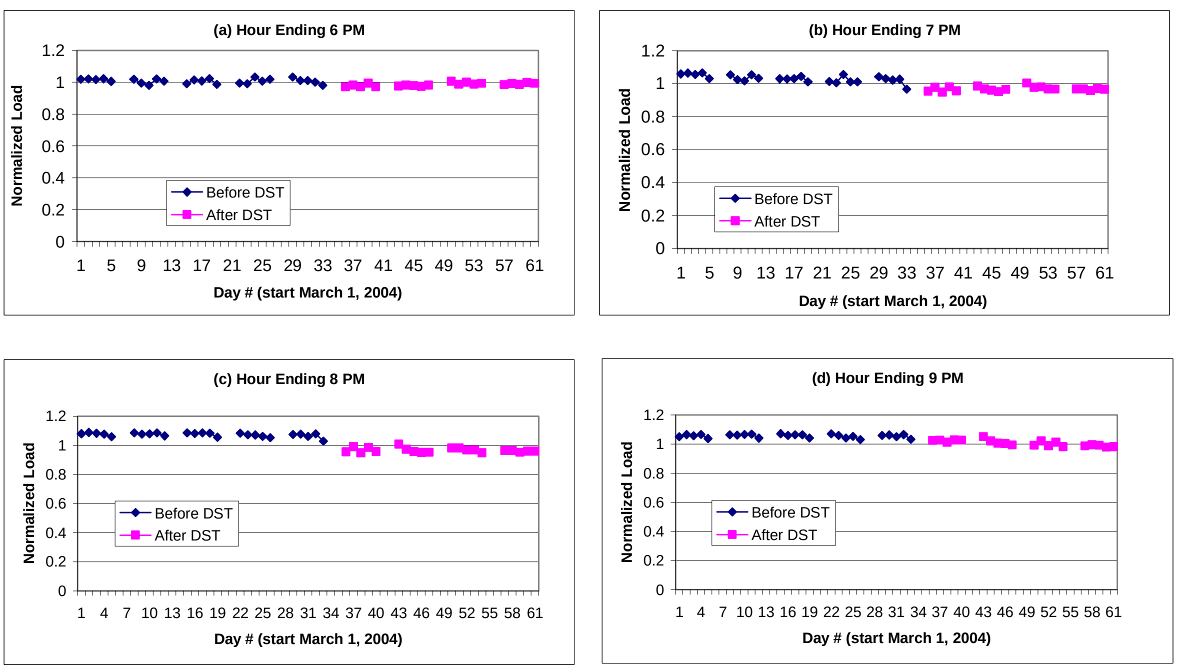
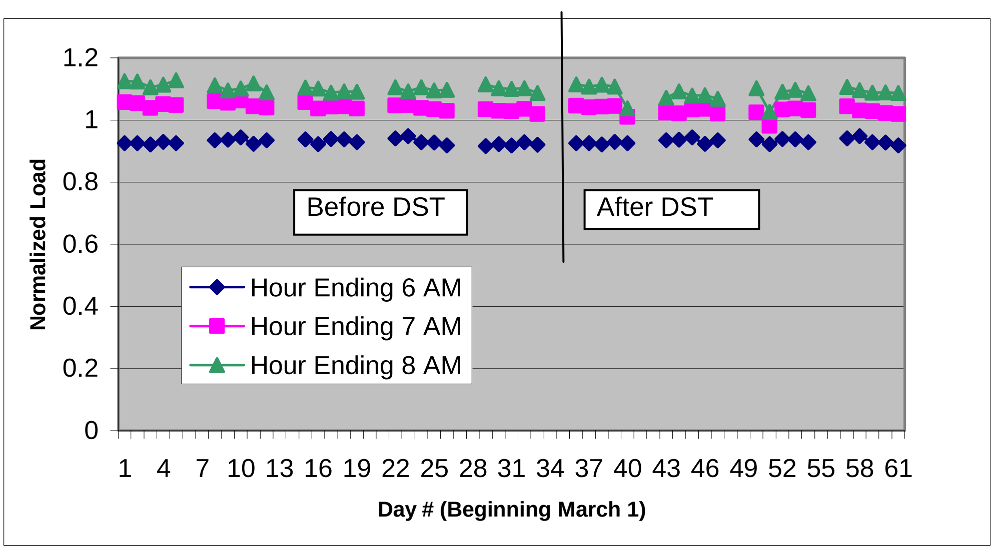


Table B.2. Estimated Coefficients for Key Variables for Spring 2004 Normalized Load Model—Detroit

System: SYS1921SUR
Estimation Method: Seemingly Unrelated Regression
Date: 02/09/06 Time: 21:38
Sample: 1 61
Included observations: 61
Total system (balanced) observations 183
Linear estimation after one-step weighting matrix

	Coefficient	Std. Error	t-Statistic
Variables - Hour 19			
Constant	1.14195	0.01503	76.0
Daylight19	-0.11713	0.01689	-6.9
Daylight20	-0.04688	0.00488	-9.6
Temperature	-0.00253	0.00079	-3.2
Variables - Hour 20			
Constant	1.07837	0.00250	432.2
Daylight20	-0.10894	0.00363	-30.0
Temperature	-0.00162	0.00068	-2.4
Variables - Hour 21			
Constant	1.05412	0.00222	476.0
Daylight21	-0.08368	0.00511	-16.4
Temperature	-0.00078	0.00062	-1.2

Figure B.5. Normalized Loads for Morning Hours for March-April 2004 in Detroit



B.3 Texas Utility

The Texas utility for which demand data were analyzed shows quite different behavior in comparison to Portland or Detroit. The plots of demands vs. temperatures for morning, day, and two evening hours for the March-April 2004 time period are shown in Figure B.6.[53] The responses of electricity use show that the response to temperature is related to cooling demand, with the exception of the early morning hours for much of the two-month period. Only in the 7 p.m. evening hour is there an appreciable difference in the demands at the same temperature before and after the DST transition.

Figure B.7 shows the normalized load plots for the four evening hours beginning with the 5 to 6 p.m. hour in the upper-left chart. Only in the hour ending at 8 p.m. is there a marked decline in the demands after the DST transition on April 4.

Table B.3 presents the coefficient estimates and standard errors for the key variables—daylight and temperature. As for Detroit, the normalized load equations were estimated as a system for three hours (as shown in Figure B.7), starting with the hour ending at 7 p.m. The estimated coefficient for daylight during the hour ending at 7 p.m. is higher than that for 8 p.m., although not as statistically significant. Even though the coefficient is higher, the change in the fraction of daylight during the 6 p.m. to 7 p.m. hour (from the beginning of March to DST transition) is not as great as that in the subsequent hour.[54] Thus, the major impact on the demands over the DST transition on April 4 is observed during the 7 p.m. to 8 p.m. hour, as reflected in the normalized load plots. The signs on the temperature difference variables are all positive, consistent with buildings using electricity for cooling during this time of the year.

[53] A constant value has been subtracted from all of the actual demands plotted in Figure B.6 to mask identification of the specific utility.

[54] The daylight coefficient represents the change in the normalized load, going from zero minutes of daylight during the hour to daylight during the entire hour. The actual or predicted change in the demand is the product of the change in fraction of daylight during the hour multiplied by the daylight coefficient. Because there is little change in daylight during the 6 p.m. to 7 p.m. hour under EDST for this utility, the predicted change in the demand is very small as shown in Table 3.6 in the body of the report.

Figure B.6. Demand vs. Temperature for Weekdays in March-April 2004 for Texas Utility

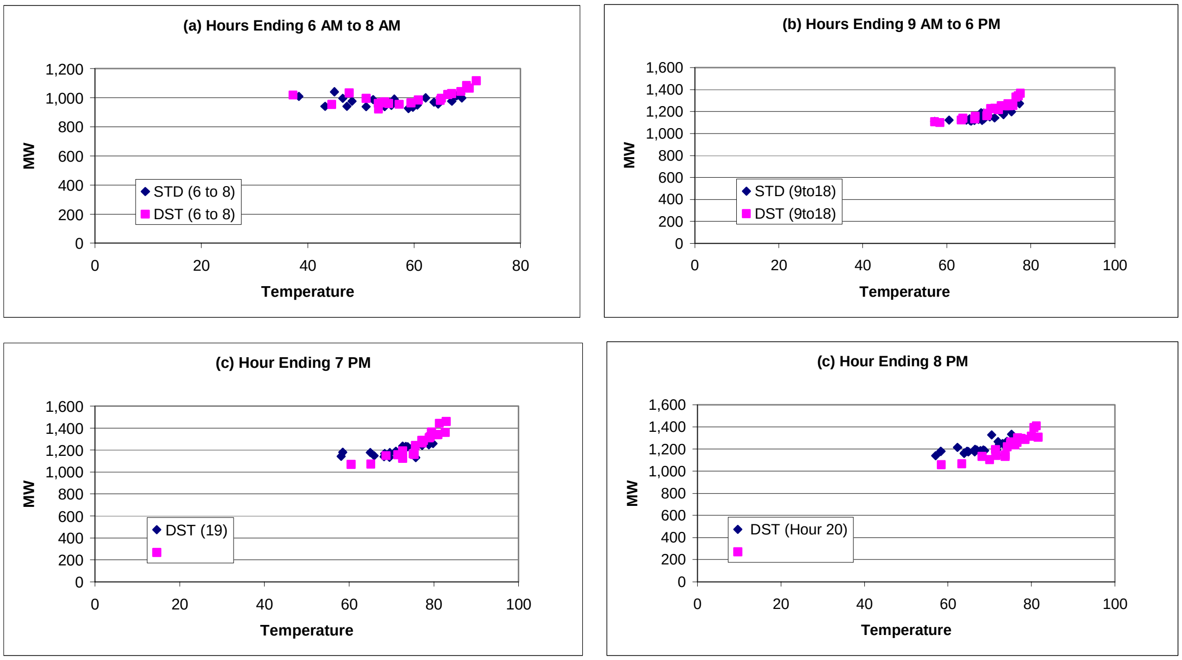


Figure B.7. Normalized Loads for March-April 2004 in Texas Utility

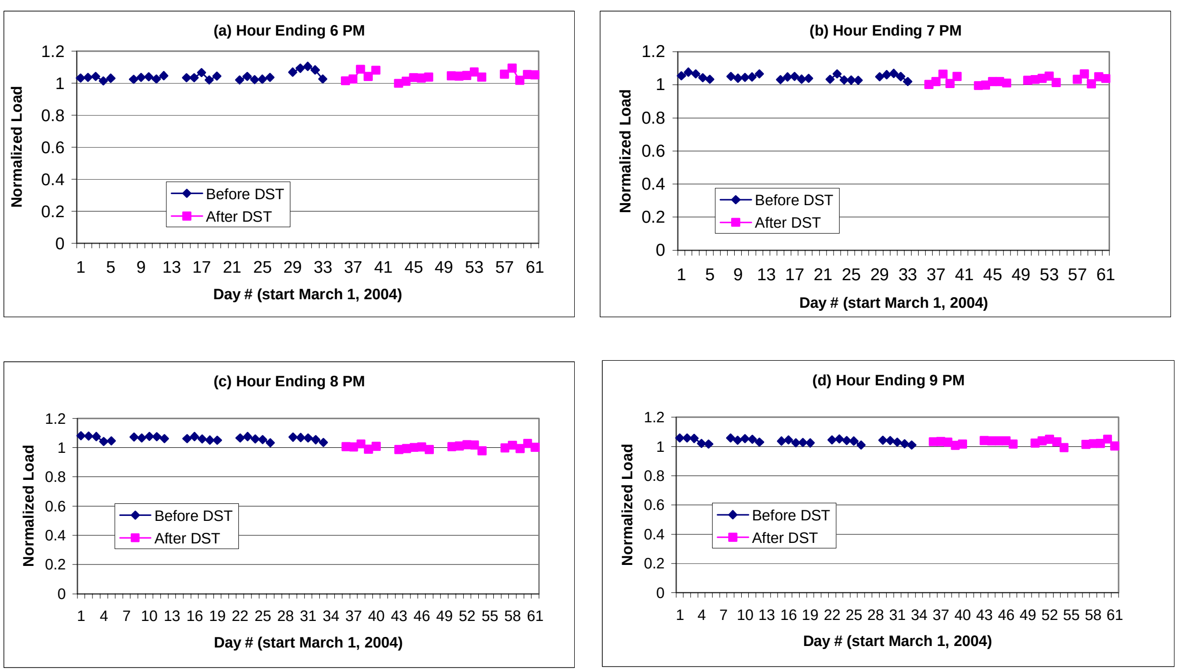


Figure B.8 shows the normalized loads for three morning hours over March and April of 2004. For this location, the fraction of daylight during the 6 a.m. to 7 a.m. hour increases from about 30 percent to 90 percent before the transition to DST on April 4. The decline in the normalized loads during this time period is consistent with increasing daylight. Unexplained, however, is no significant increase in the demand in the week following DST transition, although the demand increases in the subsequent week. When the normalized load model was estimated for this hour, the resulting coefficient on the daylight variable was about -0.03—reflecting an average response of the demand to daylight over the entire time period. When applied to the change in daylight during the morning hours under EDST (i.e., DST starting on March 14), the average change in the demand was about 3 percent, as shown in Table 3.6 in the body of the report.[55]

Table B.3. Estimated Coefficients for Key Variables for Spring 2004 Normalized Load Model—Texas Utility

System: SYS1921SUR
Estimation Method: Seemingly Unrelated Regression
Date: 02/09/06 Time: 17:18
Sample: 1 61
Included observations: 61
Total system (balanced) observations 183
Linear estimation after one-step weighting matrix

	Coefficient	Std. Error	t-Statistic
Variables - Hour 19			
Constant	1.1062	0.0209	52.9
Daylight19	-0.0790	0.0226	-3.5
Temperature	0.0012	0.0007	1.7
Variables - Hour 20			
Constant	1.0599	0.0023	459.0
Daylight20	-0.0560	0.0029	-19.5
Temperature	0.0009	0.0006	1.7
Variables - Hour 21			
Constant	1.0421	0.0031	340.3
Daylight21	-0.0615	0.0158	-3.9
Temperature	0.0025	0.0007	3.5

[55] When the regression model was estimated for only one hour during the morning, some imputation of the response was made for the adjacent hour in which daylight would change significantly under EDST. In this case, most of the response is predicted to occur in the 6 a.m. to 7 a.m. hour (2.1 percent), but some increase in the demand is also assumed to occur in the subsequent hour (7 a.m. to 8 a.m.) hour (0.9 percent). These values were reported in Table 3.7, above. In this case, a demand response to daylight was not estimated from the historical data for the 7 a.m. to 8 a.m. hour, as there was nearly complete daylight for this hour during all days in the estimation period. Under EDST, however, the transition to daylight time in mid-March would impact the fraction of daylight during this hour.

Figure B.8. Normalized Loads for Morning Hours for March-April 2004 in Texas Utility